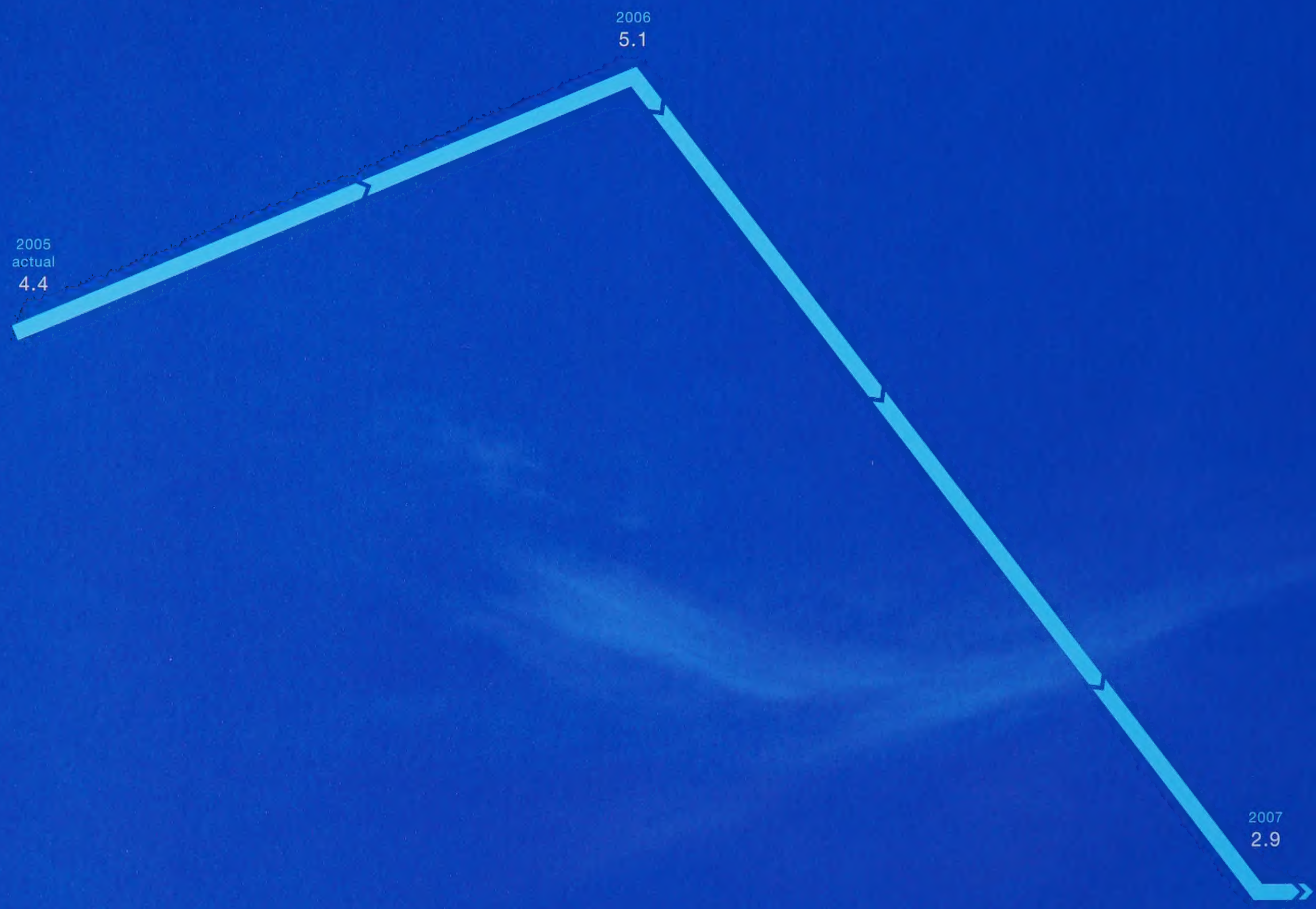

nexen
annual report 05
we're **on** to something big

investments

$5 billion behind pipe in 2006

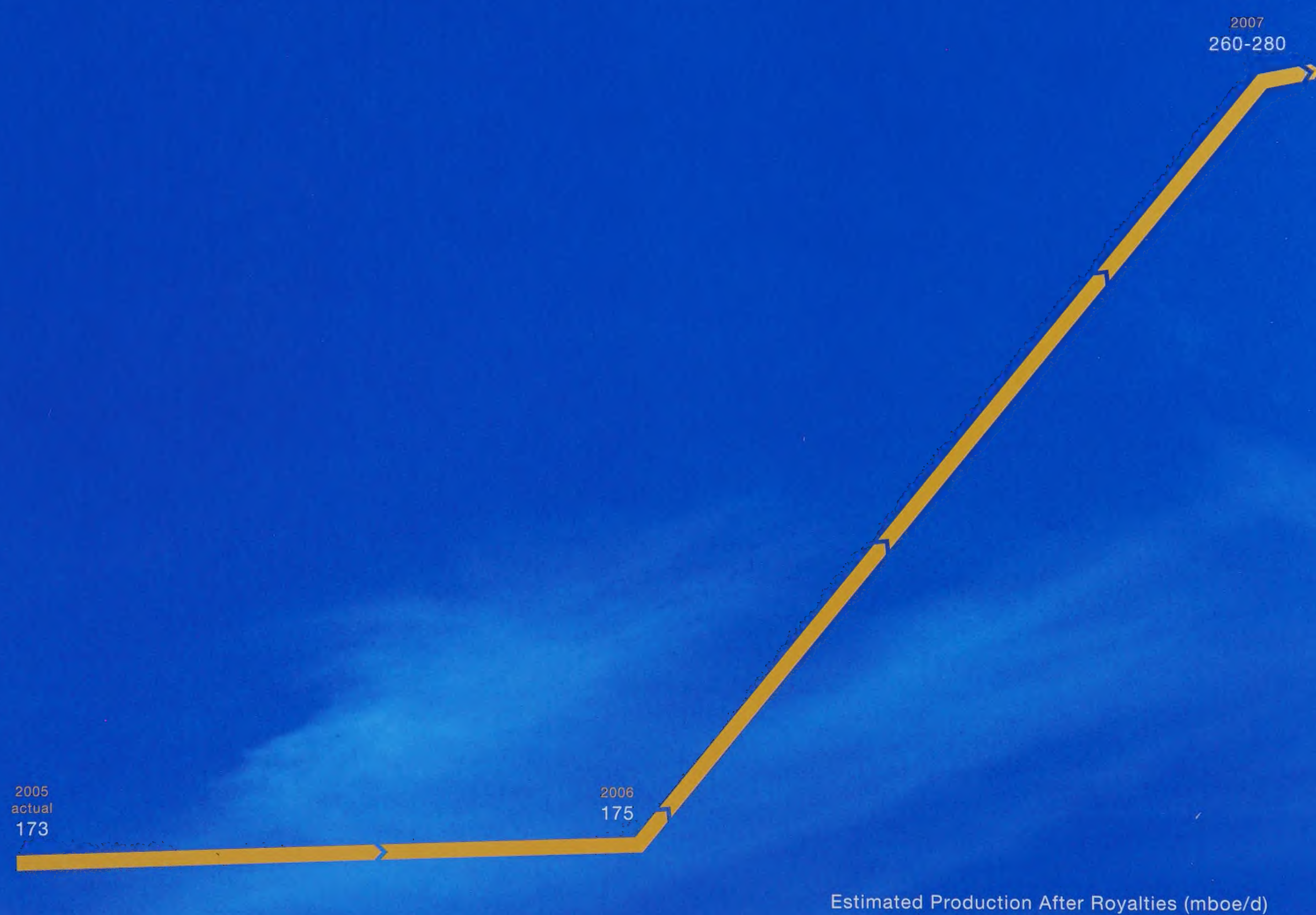


Estimated Development Capital Behind Pipe (Cdn$ billions)

on track For several years, we've been strategically positioning ourselves with big development projects in key basins, including Buzzard in the North Sea, Long Lake in the Athabasca oil sands and Syncrude's Stage 3 oil sands expansion. By late 2006, we'll have invested approximately $5 billion in these world-class legacy projects that aren't yet delivering production or cash flow, but soon will be.

production

after royalties, up 50% in 2007



on stream Our production from these investments starts this summer as Syncrude's expansion begins to add 8,000 bbls/d and Buzzard comes on stream in late 2006. Big growth is expected to arrive in 2007 as royalty-free Buzzard climbs to 85,000 boe/d and Long Lake has capacity to reach 30,000 synthetic bbls/d, both net to us. We expect 2007 production after royalties to grow by 50% over current volumes.

We're on target to grow 2007 production after royalties by approximately 50% over current volumes. We're bringing on stream one of the largest projects in the UK North Sea. We've just drilled the deepest oil discovery ever in the Gulf of Mexico that may unfold into a world-class discovery. We're moving full steam ahead to develop 5 billion barrels of oil sands resource in phases, using technology that gives us a significant cost advantage over our competitors. We've begun commercial development of our large coal bed methane resource in Canada. And we're pursuing our largest exploration program ever in 2006, drilling 20 high-impact wells in opportunity-rich areas worldwide. We are Nexen—a successful, Canadian-based, global energy company.

And we're on to something big.

see the **value**

growth

cash flow per share also up 50% in 2007

Estimated Cash Flow per Share (Cdn$/share)
Assuming US$50/bbl WTI and US$0.85 to Cdn$1.00 exchange rate

ongoing Production increases deliver solid value, as 2007 cash flow per share is expected to also grow by about 50%. We have big capacity for further success. Sequential oil sands development is expected to deliver 120,000 bbls/d by 2016. Our coal bed methane project targets 150 mmcf/d by 2011. Usan, offshore Nigeria, could add 30,000 bbls/d by 2010. And significant exploration opportunities could boost this further.

success that speaks highly of our people

on course Our record financial results in 2005 build on the more than 30 years of profitability we've delivered. Going forward, we've defined an impressive growth profile from our large, balanced portfolio of superior projects. That's because people at Nexen have the courage to believe in and implement our strategy with ingenuity and integrity over the long term.

	2005	2004	2003
Capital Expenditures ($ millions)	**2,638**	1,681	1,494
Business Acquisitions ($ millions)	**–**	2,583	–
Production before Royalties (mboe/d)	**242**	250	269
Production after Royalties (mboe/d)	**173**	174	185
Cash Flow from Operations ($ millions)	**2,403**	1,942	1,795
Cash Flow per Share ($/share)	**9.23**	7.55	7.25
Net Income ($ millions)	**1,152**	793	578
Net Income per Share ($/share)	**4.43**	3.08	2.33
Proved Reserves[1] (mmboe)	**786**	843	811
Probable Reserves[1] (mmboe)	**835**	807	724
Proved + Probable Reserves[1] (mmboe)	**1,621**	1,650	1,535

1 Represent our working interest before royalties using year-end pricing.

Nexen made great strides in every area of the company in 2005. With our value-based strategy, strong assets and highly capable people, we're **on** track for even bigger success.

This past year was our best ever. In 2005, our people focused on successfully integrating our 2004 North Sea acquisition, completing lucrative Canadian asset dispositions, and restructuring our chemicals business into an income trust and selling about 39% of it to the public. We did this while keeping our major development projects on track, announcing more exploration success, battling Gulf hurricanes while ensuring human safety, and maintaining our existing production so we could capitalize on high commodity prices and deliver record financial results.

Cash flow was a record $2.4 billion or $9.23 per share, and net income soared to $1.15 billion or $4.43 per share, also a new high. Production was within our initial target range, despite selling approximately 18,300 boe/d of conventional Canadian production mid-year and encountering significant downtime from hurricanes in the Gulf of Mexico. Marketing had a great year, capitalizing on significant market volatility. And we had a successful year with the drill bit, with several small discoveries in the North Sea and Gulf of Mexico, and a potential world-class discovery at Knotty Head in the deep-water Gulf.

On the reserve front, we added 82 mmboe of proved reserves, replacing 91% of our production. Proved and probable reserves totaled 1,621 mmboe, more than double our proved reserves. This reflects significant future value. To date, we've only booked 231 mmboe of proved reserves for Syncrude Stage 3, Buzzard and our coal bed methane (CBM) project, and none for Long Lake or our recent exploration success at Knotty Head in the Gulf of Mexico. So there are more reserves to come as we complete our major projects, delineate discoveries and sanction new development projects.

Creating long-term value has always been our strategy, and to do that, we look at the big picture

and plan ahead. This strategy is proving its worth. Energy supply concerns are keeping prices high and creating demand for renewable sources. Cost pressures are squeezing margins for oil and gas companies. Yet Nexen is ahead of the curve. With longer-term developments in opportunity-rich areas, we are well positioned to continue delivering great returns for our shareholders. I believe we have a significant advantage over our peers.

In fact, no other company our size offers the suite of assets and opportunities we do: oil sands and CBM projects in Canada, deep-water plays in the Gulf of Mexico, and strong international holdings. We are building capacity where the opportunities are greatest, securing opportunities for value creation before they become widely apparent, as opposed to chasing them in overheated markets. As early movers into Canada's oil sands and CBM and the deep-water Gulf of Mexico, we've assembled land positions that are simply not available today. In each area, we have what it takes to build sustainable businesses, with legacy assets in the making that will act as catalysts for long-term value creation. And we have the people and technology to make it happen. Packaged together, this creates tremendous capacity.

For the past few years, we've been telling you about our exciting growth opportunities in the Athabasca oil sands, Gulf of Mexico, North Sea, offshore West Africa and Yemen. We've worked diligently to keep our major development projects on time and on budget. Now, we are less than a year away from bringing significant new production on stream at Syncrude and Buzzard, followed by Long Lake in

The **on**going rewards in production and cash flow will be significant.

2007. We expect both production after royalties and cash flow per share to jump approximately 50% in 2007, as demonstrated by the graphs at the beginning of this report.

In patiently building our portfolio, we've had the courage of conviction to stay on course when, frankly, deviating would have been easy. But that's what builds capacity: developing in-house technical skills, securing early and large land positions in key areas, nurturing relationships with local governments and communities, understanding environmental and safety issues, and then moving forward with a plan that addresses all issues while generating attractive returns. All of our major projects can earn their cost of capital with WTI oil prices in the mid-US$20s per barrel. So we are well positioned to earn strong returns with today's higher prices.

In the oil sands, we have more than 5 billion barrels of recoverable resource and a phased sequential approach for development—each phase capitalizing on what we've learned in the previous ones. Our approach enables us to control the pace of growth and effectively manage our capital programs as we go. Long Lake is the first phase, developing only 10% of our total resource. We're now planning Phase 2 and looking ahead to future phases. We'll essentially duplicate Long Lake over and over again and expect to reach 120,000 bbls/d (net to us) of synthetic crude oil by 2016. Our CBM development has similar characteristics. Production from our initial development wells is exceeding our expectations, and we are accelerating our investment to increase rates substantially over the next few years. With over 600 net sections of land containing more than 3 TCF of resource in place, we have the running room to sustain long-term development and gain efficiencies for improved performance with each well we drill.

We are also very excited about Knotty Head—our first sub-salt discovery and the deepest oil discovery ever drilled in the Gulf of Mexico. Knotty Head has 600 feet of net pay in a large structure. With appraisal work currently underway, we're confident this will unfold as a major discovery that will provide significant new production later in the decade. We have a strong position in this emerging sub-salt play and equally important, we are experts in using technology to find oil below the thick salt layers that characterize this play. We have also amassed a substantial inventory of prospective acreage throughout the deep-water Gulf, and we're continuing a very active exploration program that builds on our success.

Internationally, our world-class Buzzard project in the North Sea is coming on stream late this year at very high flow rates. Over the next few years, we expect to add to this royalty-free production by tying-in a number of smaller discoveries to existing facilities. We have many more exploration opportunities in the region. Offshore Nigeria, a preliminary field development plan has been submitted to Nigerian government agencies for approval. And in Yemen, our legacy assets are continuing to deliver significant free cash flow to help fund our ongoing capital programs.

As you can see, our portfolio provides a good balance between annuity-type assets in oil sands and CBM, and exciting exploration opportunities in the Gulf of Mexico. Our annuity-type assets mirror a manufacturing business: significant upfront capital investment with stable, long-term production and cash flow and predictable growth from additional investment. Our best example is our oil sands

Add our focus **on** integrity, and you can see the value.

development where each phase can provide 40 years of steady volumes. What a great complement to growth through exploration success, which typically delivers higher production plateaus for shorter durations. With significant value in both annuity and exploration assets in prize locations globally, Nexen is well positioned for future growth.

Augmenting this advantage is our diverse skill-set and willingness to apply innovative technology. Through the years, we have worked globally, developing our operating skills in all types of terrain—water, sand and muskeg. In 2005, we participated in approximately one-third of the deep-water discoveries in the Gulf of Mexico and operated two of the nine wells. Our skills and experience are very valuable and transferable, as many of the world's discoveries are in deep water. These skills are also coming in handy offshore West Africa, reflecting some of the synergies in our choice of operating locations around the world. At Long Lake, we've combined OrCrude™ technology to upgrade bitumen with gasification technology to generate fuel from the low-value end of the barrel. We expect to create a significant cost advantage here. Our methodology is turning heads in the industry, as today's high cost of natural gas is now causing other companies to look at alternate fuel options. With the oil sands estimated to hold 1.7 trillion barrels of bitumen in place—the world's second largest resource behind Saudi Arabia—it is important to develop it economically. And we're on it.

As we move forward, we're working hard to manage the risks our programs face. With big multi-year projects, early and extensive planning is key. At Long Lake, we've committed more than two-thirds of the project costs, in line with our estimates, and we're keeping a close eye on labour availability and productivity—our biggest remaining cost uncertainty. The shortage of skilled labour in Alberta is

a real issue. At Nexen, we continuously invest in educational institutions at all levels and provide scholarships to Canadian and Yemeni students. We're working with industry to develop qualified trades people by supporting their advanced training while they work on our Long Lake project. Education is a priority, as we see the value it has. It changes lives, opens doors and creates new horizons.

With our large exploration program, another factor to manage is rig availability. We're planning 20 high-impact wells this year, primarily in the Gulf of Mexico, North Sea, offshore West Africa and Yemen. To ensure we can drill these wells, we have secured most of the rigs we need. We've also recently committed to take a new-build, fifth-generation semi-submersible drilling rig for two years following its delivery in mid-2009.

Our business goes beyond drilling wells. Wherever we operate in the world, we communicate our plans and progress with local communities, governments and other affected stakeholders. Our success depends on building relationships and understanding sometimes competing stakeholder agendas. In some locations, the complexities are not for the faint of heart. But we choose to be there because we believe we can manage the risks and generate substantial rewards for all parties.

To support transparency, we've implemented extensive community consultation practices. We first developed them for communities affected by our sour gas operations in Canada. Since then, we've continued to refine and apply these practices around the world; for example in Yemen, where we acknowledged the importance of respecting and integrating cultural sensitivity into our operations.

president & ceo
charlie fischer

As we develop our CBM and oil sands in Canada, cooperation with communities is integral to our process. We welcome participation from interested community members and promise to keep affected parties informed of our ongoing operations.

You can see the value in the way we do business. We've won a number of awards this past year, highlighted at the back of this report. These include an award for our outstanding safety record in the Gulf of Mexico, and awards for our investor relations website and annual report, reflecting our commitment to continuous, transparent disclosure. We also received a governance award that recognizes our high-quality independent board of directors whose guidance we appreciate. At the end of the day, good business practices lead to long-term profitability and solid returns. Plus, it makes our employees proud of what we do.

Everyday, I hear stories of why people come to Nexen. Nexen is a place to work on world-class projects, a place to bring big ideas to the table and see them through: on time and on budget. It's a place where people can live personal values of ethics and integrity without compromise. And, it's a fun and exciting place where we celebrate our successes. I find it very rewarding to see the pride Nexen employees have in their jobs and to watch a workforce gain technical and leadership skills for repeat success on future projects. I congratulate you all.

Our theme, we're on to something big, captures the excitement I have in Nexen's future. I am proud to lead this team of talented and qualified people toward even bigger rewards for our company, our shareholders and the communities where we operate. I look forward to keeping you informed throughout the year and also at our AGM in Calgary on April 27.

learn more

Communicating with stakeholders is about creating understanding. We want you to understand our plans, progress and results. Our 10-K and other information that follow discuss our:

We also produce a number of documents to assist you:

Proxy Circular Learn about our board, officers, corporate governance practices and details about the AGM on April 27, 2006.

Statistical Supplement Download detailed historical operating and financial information for Nexen and our segmented operations.

Sustainability Report Learn about our way of doing business and progress toward improving our safety, environment and social responsibility performance.

Website Check out the investor toolkit at www.nexeninc.com/investors to view these documents online or to order a hard copy. Our website also contains information including news releases, investor presentations, quarterly reports, conference call scripts and more.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

**ANNUAL REPORT PURSUANT TO SECTION 13 or 15(d) of
THE SECURITIES EXCHANGE ACT OF 1934**

For the year ended December 31, 2005

Commission File Number 1-6702

NEXEN INC.

nexen

Incorporated under the Laws of Canada

98-6000202
(I.R.S. Employer Identification No.)

801 – 7th Avenue S.W.
Calgary, Alberta, Canada T2P 3P7
Telephone - (403) 699-4000
Web site - www.nexeninc.com

Securities registered pursuant to Section 12(b) of the Act:

Title	Exchange Registered On
Common shares, no par value	The New York Stock Exchange The Toronto Stock Exchange
Subordinated Securities, due 2043	The New York Stock Exchange The Toronto Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes _√_ No ___

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.

Yes ___ No _√_

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months, and (2) has been subject to such filing requirements for the past 90 days.

Yes _√_ No ___

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrant is large accelerated filer, an accelerated filer, or a non-accelerated filer.

Large accelerated filer _√_ Accelerated filer ___ Non-accelerated filer ___

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ___ No _√_

On June 30, 2005, the aggregate market value of the voting shares held by non-affiliates of the registrant was approximately Cdn $9.7 billion based on the Toronto Stock Exchange closing price on that date. On January 31, 2006, there were 261,614,723 common shares issued and outstanding.

TABLE OF CONTENTS

Special Note to Canadian Investors—see page 80

Unless we indicate otherwise, all dollar amounts ($) are in Canadian dollars, and oil and gas volumes, reserves and related performance measures are presented on a working interest before-royalties basis. Where appropriate, information on an after-royalties basis is provided in tabular format. Volumes and reserves include Syncrude operations unless otherwise stated.

Below is a list of terms specific to the oil and gas industry. They are used throughout the Form 10-K.

/d	=	per day	mboe	=	thousand barrels of oil equivalent
bbl	=	barrel	mmboe	=	million barrels of oil equivalent
mbbls	=	thousand barrels	mcf	=	thousand cubic feet
mmbbls	=	million barrels	mmcf	=	million cubic feet
mmbtu	=	million British thermal units	bcf	=	billion cubic feet
km	=	kilometre	WTI	=	West Texas Intermediate
MW	=	megawatt	NGL	=	natural gas liquid

In this 10-K, we refer to oil and gas in common units called barrel of oil equivalent (boe). A boe is derived by converting six thousand cubic feet of gas to one barrel of oil (6mcf/1bbl). This conversion may be misleading, particularly if used in isolation, as the 6mcf/1bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the well head.

The noon-day Canadian to US dollar exchange rates for Cdn$1.00, as reported by the Bank of Canada, were:

(US$)	December 31	Average	High	Low
2001	0.6279	0.6458	0.6695	0.6241
2002	0.6331	0.6369	0.6618	0.6199
2003	0.7738	0.7135	0.7738	0.6350
2004	0.8308	0.7683	0.8493	0.7159
2005	0.8577	0.8253	0.8690	0.7872

On January 31, 2006, the noon-day exchange rate was US$0.8742 for Cdn$1.00.

Electronic copies of our filings with the Securities Exchange Commission (SEC) and the Ontario Securities Commission (OSC) (from November 8, 2002 onward) are available, free of charge, on our website (www.nexeninc.com). Filings prior to November 8, 2002 are available free of charge, on request, by contacting our investor relations department at (403) 699-5931. As soon as reasonably practicable, our filings are made available on our website once they are electronically filed with the SEC or the OSC. Alternatively, the SEC and the OSC each maintain a website (www.sec.gov and www.sedar.com) that contains our reports, proxy and information statements and other published information that have been filed or furnished with the SEC and the OSC.

As conventional basins in North America mature, the transition of our operations is **on** track toward major projects in established basins, exploration in newer basins and exploitation of unconventional resources.

see the **value**

operations

PART I

Items 1 and 2. **Business and Properties**

ABOUT US

Nexen Inc. (Nexen, we or our) is an independent, Canadian-based, global energy company. We were formed in Canada in 1971 by the combination of the Canadian crude oil, natural gas, sulphur and chemical operations of two subsidiaries of Occidental Petroleum Corporation (Occidental). We've grown from producing 10,700 boe/d before royalties with revenues of $26 million in 1971, to 241,700 boe/d before royalties (including Syncrude production) and revenues of $4.1 billion in 2005. We achieved this growth through exploration success and strategic acquisitions. In more than 30 years of operations, we have been profitable every year, except one, and have been paying quarterly dividends consecutively since 1975.

In the 1970s, we expanded our Western Canadian assets and entered the US Gulf of Mexico. We finished this decade with production of approximately 11,000 boe/d before royalties and revenues of $126 million.

In the 1980s, we continued to expand in Western Canada by acquiring Canada-Cities Service, Ltd. in 1983. This acquisition doubled our size and included an interest in the Syncrude Joint Venture, our entry into the Athabasca oil sands. Acquisitions of Cities Offshore Production Co. in 1984 and Moore McCormack Energy, Inc. in 1988 further increased our presence in the Gulf of Mexico. We finished this decade with production of approximately 68,600 boe/d before royalties and revenues of $591 million.

In the 1990s, we had two defining moments: discovering oil on the Masila block in Yemen and acquiring Wascana Energy Inc. The first of 17 fields at Masila was discovered in 1991, and Masila has produced more than 890 million barrels since start-up. Our 1997 purchase of Wascana Energy Inc. almost tripled our Canadian production. In 1998, we entered Australia with an interest in the offshore Buffalo field and Nigeria as the operator of the Ejulebe field. Also in 1998, we discovered Ukot on Block OPL-222, offshore Nigeria, the first of several discoveries to date on the block. We finished this decade with production of approximately 239,200 boe/d before royalties and revenues of $1.7 billion.

So far in the 21st century, we have made a number of discoveries, two strategic acquisitions and completed a non-core divestiture program. In 2000, we discovered Gunnison in the deep-water Gulf of Mexico and Guando in Colombia. That same year, we joined with Ontario Teachers' Pension Plan Board (Teachers) to acquire Occidental's remaining 29% interest in us. Teachers purchased 20.2 million common shares. We repurchased the remaining 20 million common shares for $605 million, which would have had a value of more than $2.2 billion at year-end 2005. We also exchanged our oil and gas operations in Ecuador for Occidental's 15% interest in our chemical operations and we changed our name to Nexen Inc. from Canadian Occidental Petroleum Ltd. In 2001, we discovered Aspen in the deep-water Gulf of Mexico and signed a joint venture agreement with OPTI Canada Inc. to develop, produce and upgrade bitumen at Long Lake in the Athabasca oil sands. In 2002, we discovered Usan, the second discovery on OPL-222, offshore Nigeria. In late 2003, we discovered two fields on Block 51 in Yemen. And in 2004, we acquired properties in the UK North Sea, providing us with strategic operatorship of the Buzzard discovery, the producing Scott and Telford fields and 700,000 acres of exploratory acreage.

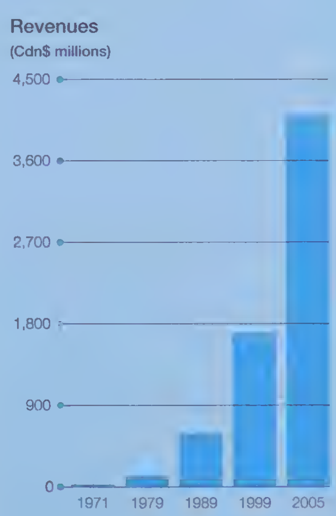
In the third quarter of 2005, we sold Canadian conventional oil and gas properties producing approximately 18,300 boe/d before royalties. We also monetized 39% of our chemical business through the initial public offering of the Canexus Income Fund. During the year, we made a potentially significant discovery in the Gulf of Mexico at Knotty Head and commenced commercial development of our first coal bed methane (CBM) project in the Fort Assiniboine area in Western Canada. Now in 2006, we are on track to complete major development projects at Buzzard in the North Sea and the Syncrude Stage 3 expansion, followed by Long Lake in the Athabasca oil sands in 2007. These projects and an active exploration program provide future growth for our company.

For financial reporting purposes, we report on four main segments:

- oil and gas;
- Syncrude;
- oil and gas marketing; and
- chemicals.

Western Canada

Nexen is an independent, Canadian-based, global energy company.



Gulf of Mexico drill ship

Our goal is to grow long-term value for shareholders.

We expect our 2007 production after royalties to grow by more than 50% over current volumes.

Our oil and gas operations are broken down geographically into the UK North Sea, US Gulf of Mexico, Canada, Yemen and Other International (Colombia and offshore West Africa). Results from our Long Lake project are included in Canada. Syncrude is our 7.23% interest in the Syncrude Joint Venture. Marketing includes our growing crude oil, natural gas, natural gas liquids and power marketing business in North America and southeast Asia. Chemicals includes operations in North America and Brazil that manufacture, market and distribute sodium chlorate, caustic soda and chlorine.

Production, revenues, net income, capital expenditures and identifiable assets for these segments appear in Note 20 to the Consolidated Financial Statements and in Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) in this report.

STRATEGY

Our goal is to grow long-term value for shareholders. We define value growth as increasing reserves, production and cash flow over the long term. We believe in developing targeted capabilities, which generate opportunities and operations required for long-term success in our ever-evolving industry. As conventional basins in North America mature, we have developed specific capabilities in oil sands, coal bed methane, deep-water technology and international locations. These enable us to focus on specific types of projects, as we transition toward major projects in established basins, exploration in newer basins and exploitation of unconventional resources.

Today, we are building new sustainable businesses in Western Canada, the North Sea, Gulf of Mexico, Middle East and offshore West Africa, capitalizing on the following corporate strengths:

- We are successful deep-water explorers with significant discoveries at Knotty Head in the Gulf of Mexico and at Usan, offshore Nigeria;
- We are skilled project managers with major development projects at Buzzard in the North Sea, and Long Lake in Canada's Athabasca oil sands. These projects are nearing completion on time and on budget;
- We are innovative in our application of technology. Long Lake is expected to be the first oil sands project to use gasification technology to significantly reduce the cost of producing bitumen;
- We are an international operator with a proven track record of successful business ventures in Yemen, Colombia and Australia; and
- We make value-oriented acquisitions. In 2001, we purchased approximately 15% of our own shares, and in 2004, we made a strategic entry into the UK North Sea.

The location and scale of our operations often result in an extended period of time from the capture of opportunities to first production and non-linear year-over-year growth in reserves and production. Significant up-front capital investment is often required prior to realizing production and free cash flows. We fund this investment by maximizing cash flow from our producing assets, issuing long-term debt and selling non-core assets into attractive markets.

Our long-term strategy focuses on ensuring sufficient inventory of opportunities for future growth. Our major development project at Buzzard is expected to add significant production in late 2006, followed by Long Lake in 2007. With these projects on stream, we expect our net production in 2007 to grow by more than 50%, net of declines. Beyond 2007, we have a number of growth opportunities, including undeveloped discoveries at Knotty Head in the Gulf of Mexico and Usan and Ukot offshore Nigeria, together with future phases of our oil sands projects that we plan to develop sequentially.

In creating sustainable businesses, we are committed to good corporate governance and social responsibility. We believe that over the long term, companies that follow sustainable business practices outperform those with narrower priorities. We foster dialogue with stakeholders about our operational opportunities and challenges, from exploration to production to reclamation. Our goal is to help stakeholders become engaged participants in a continuing consultation process, while balancing their multiple, and sometimes conflicting goals.

UNDERSTANDING THE OIL AND GAS BUSINESS

The oil and gas industry is highly competitive. With strong global demand for energy, there is intense competition to find and develop new sources of supply. Yet, barrels from different reservoirs around the world do not have equal value. Their value depends on the costs to find, develop and produce the oil or gas, the fiscal terms of the host regime and the price products command at market based on quality and marketing efforts. Our goal is to extract the maximum value from each barrel of oil equivalent, so every dollar of capital we invest generates an attractive return.

Numerous factors can affect this. Changes in crude oil and natural gas prices can significantly affect our net income and cash generated from operating activities. Consequently, these prices may also affect the carrying value of our oil and gas properties and how much we invest in oil and gas exploration and development. We attempt to reduce these impacts by investing in projects we believe will generate positive returns at low commodity prices. For example, most of our major projects generate attractive returns with oil prices in the mid-US$20-per-barrel range.

We also have a broad customer base for our crude oil and natural gas. Alternative customers are generally available, and the loss of any one customer is not expected to have a significant adverse effect on the price of our products or our revenues. Oil and gas producing operations are generally not seasonal. However, demand for some of our products can have a seasonal component that can impact price. In particular, heavy oil is generally in higher demand in the summer for its use in road construction, and natural gas is generally in higher demand in the winter for heating. Our realized prices for our oil and gas products are mainly determined by volatile international crude oil markets and by North American gas markets and, as a result, we are price takers.

We manage our operations on a country-by-country basis, reflecting differences in the regulatory and competitive environments and risk factors associated with each country.

OIL AND GAS OPERATIONS

We have oil and gas operations in the UK North Sea, US Gulf of Mexico, Western Canada, Yemen, offshore West Africa and Colombia. We also have operations in Canada's Athabasca oil sands which produce synthetic crude oil. We operate most of our production and continue to develop new growth opportunities in each area by actively exploring and applying technology.

Yemeni employee at Masila

Most of our major projects generate attractive returns with WTI oil prices in the mid-US$20s per barrel.

2005 Production Before Royalties

Jack-up drill rig and Buzzard wellhead deck

North Sea—United Kingdom (UK)

The UK is one of our key growth areas. In 2004, we acquired a 43.2% operated interest in the Buzzard development, operated interests in the Scott and Telford producing fields, the Scott production platform, interests in several satellite discoveries and more than 700,000 net undeveloped exploration acres for US$2.1 billion. This acquisition established us as a significant regional player with concentrated assets, infrastructure and exploration and development potential for future growth. It added high-margin reserves and production, diversified our worldwide portfolio by adding strong assets in a stable jurisdiction, and complemented our other longer cycle-time projects.

Our UK strategy is focused on exploration and exploitation opportunities near existing infrastructure. We have a number of exploitation opportunities in our existing fields and smaller satellite discoveries near infrastructure. Most of our unexplored acreage is near Scott/Telford or Buzzard where new discoveries could be tied-in quickly, upon success.

At year end, the UK had proved reserves of 145 mmboe before royalties (145 mmboe after royalties) representing about 18% of Nexen's total proved oil and gas and Syncrude reserves.

Buzzard is on time and on budget with first production expected by late 2006.

Buzzard Development

Buzzard is one of the largest discoveries in the UK North Sea in recent years. Discovered in 2001, it is in the Outer Moray Firth, central North Sea, about 60 miles northeast of Aberdeen, in 317 feet of water.

Development of Buzzard is on budget and on schedule with first production expected by late 2006. In 2005, we installed three platform jackets and the wellhead deck and tied-in the water injection, gas export and oil export pipelines. In October 2005, we began drilling production wells. Development of the facilities is approximately 88% complete. In summer 2006, we plan to install the utilities and production topsides and initiate hook-up and project commissioning. The facilities will have a capacity of 200,000 bbls/d of oil and 60 mmcf/d of gas. We anticipate the field will be produced through 27 production wells, of which eight will be pre-drilled and available to begin producing by late 2006. Reservoir pressure will be maintained through an active water-flood program. We estimate peak gross production rates at approximately 200,000 bbls/d of oil and approximately 30 mmcf/d of gas, with our share about 85,000 boe/d after royalties. Oil from Buzzard will be exported via the Forties pipeline to the Grangemouth refinery in Scotland. Gas will be exported via the Frigg system to the St. Fergus Gas Terminal in northeast Scotland. In 2006, we plan to invest approximately $450 million to complete the facilities and drill eight production and six water injection wells.

With Buzzard production estimated to peak at 85,000 boe/d, we expect significant growth from the UK.

UK Production

Scott and Telford are producing fields with additional exploitation opportunities. Scott, in which we have a 41% working interest, was discovered in 1987 and began producing in September 1993. We have a 54.3% working interest in Telford, which was discovered in 1991 and came on stream in 1996. In 2005, our share of Scott and Telford royalty-free production approximated 16,000 boe/d, of which 80% was oil.

Oil and gas is produced through numerous subsea wells and from wells drilled from the Scott platform. Oil is delivered to the Grangemouth refinery in Scotland via the Forties pipeline, while gas is exported via the SAGE pipeline to the St. Fergus terminal in northeast Scotland. In 2005, the Scott platform underwent a significant maintenance turnaround and facilities upgrade to improve reliability and extend

facility life. Upgrades included improvements to electric, produced water injection, and drilling and metering systems. In 2006, we plan to invest approximately $35 million to drill, complete, and tie-in three development wells and perform workovers.

Our 2004 UK acquisition included a non-operated interest in Farragon, a small satellite discovery, which was brought on stream in November 2005. At year end, our 20% share of royalty-free production from Farragon was 3,900 boe/d and is expected to average between 3,000 and 4,000 boe/d in 2006.

Nexen acreage
Producing / Development Assets
Exploitation in Progress

Exploration and Undeveloped Assets

In 2005, we drilled and found hydrocarbons at Polecat, Yeoman and Black Horse. Although the hydrocarbons discovered at Polecat and Black Horse are insufficient to warrant stand alone development, these wells may form part of a future larger development plan for the area. We have a number of smaller discoveries on operated blocks near Scott, Buzzard and third-party facilities as follows:

Field	Interest (%)	Operator Status	Comments
Ettrick	80	operated	sanctioned in February 2006 for development
Bugle	82	operated	discovery near Scott; evaluating development alternatives
Duart	50	non-operated	discovery near Scott; evaluating development alternatives
Dolphin	42	operated	discovery near Scott; evaluating development alternatives
Perth	42	operated	discovery near Scott; evaluating development alternatives
Selkirk	38	operated	evaluating development alternatives
Yeoman	50	operated	discovery near Scott; evaluating development alternatives

We recently announced our plans to develop the Ettrick field, which includes drilling three production wells tied back to a floating production, storage and offloading vessel. The field is expected to begin production in early 2008, with our share reaching approximately 16,000 boe/d. Our share of full-cycle development costs are estimated at $460 million with approximately $90 million invested in 2006. The other discoveries are in various stages of evaluation.

Ettrick will be developed using a floating production facility and is expected to begin production in early 2008.

During 2005, we drilled the Saracen and Bennachie exploration wells, which encountered noncommercial hydrocarbons and were abandoned. We also increased our land acreage by approximately 388,000 acres to support our future exploration activity. We expect to drill four exploration wells in 2006. The offshore drilling rig market is currently tight, however, we have secured drilling rigs for most of our 2006 North Sea exploration and development program.

Fiscal Terms

UK fiscal terms are favorable. New discoveries pay no royalties and result in cash netbacks that are higher than our company average. Scott is subject to Petroleum Revenue Tax (PRT), although no PRT is payable until available oil allowances have been fully utilized, which isn't expected before 2009. Once payable, PRT is levied at 50% of cash flow after capital expenditures, operating costs and an oil allowance. PRT is applicable to fields receiving development consent prior to March 1993. Buzzard, Telford and Farragon fields are not subject to PRT. PRT is deductible for corporate income tax purposes. The UK corporate income tax rate is 30% of taxable income. Income from oil and gas activities is also subject to a supplemental charge of 10%, although in a recent pre-budget announcement, the UK government said it intends to increase this to 20%, effective January 1, 2006. This increase is subject to the introduction of legislation. The amount and timing of income taxes payable depends on many factors including price, production and capital investment levels.

With royalty-free production, the UK offers favourable fiscal terms.

Gunnison SPAR

Gulf of Mexico—United States (US)

The Gulf of Mexico is an integral part of our growth strategy. Large discoveries, high success rates, production infrastructure and attractive fiscal terms make the deep-water Gulf of Mexico one of the world's most prospective sources for oil and gas. The deep-water prospects generally have multiple sands and high production rates, factors which reduce risk and improve economics. Technology to find, drill, and develop discoveries is rapidly progressing and becoming more cost effective. The deep-water Gulf is relatively near infrastructure and continental US markets, enabling discoveries to be brought on stream in a reasonable period of time.

Our strategy in the Gulf is to explore for new reserves, acquire assets with upside potential and exploit our existing asset base. We focus our exploration program on three strategic play types:

- deep-shelf gas prospects;
- deep-water prospects near existing infrastructure; and
- deep-water, sub-salt plays with potential to become new core areas.

These plays are relatively under-explored, hold potential for large discoveries and have attractive fiscal terms. The shorter-cycle times for shelf gas and deep-water prospects near infrastructure complement the longer-cycle times for deep-water sub-salt plays. Although competition in the Gulf is strong, a lot of expiring acreage becoming available over the next few years may provide us access to additional exploration opportunities.

In 2005, we invested $362 million on exploration and development activities in the Gulf. This resulted in a number of discoveries, including Knotty Head, a large, four-way dip closure in the Miocene sub-salt play. Knotty Head showcases the potential in the Gulf, as it has the potential to be a major discovery. In 2006, we plan to invest approximately $500 million in the Gulf to further our strategy.

We have more than 240 blocks in the deep-water Gulf of Mexico, one of the world's most prospective sources for oil and gas.

US Production

	2005		2004		2003	
(mboe/d)	Before Royalties	After Royalties	Before Royalties	After Royalties	Before Royalties	After Royalties
Deep-water	24.0	21.5	32.1	28.7	24.0	21.7
Shallow-water	17.6	14.6	22.6	18.8	28.5	23.7
Total	**41.6**	**36.1**	**54.7**	**47.5**	**52.5**	**45.4**

In 2005, we produced approximately 41,600 boe/d before royalties (36,100 after royalties), even after weather-related disruptions. This represents about 17% of Nexen's total production. Weather is a risk in the Gulf of Mexico: specifically tropical storms and hurricanes can damage facilities, drilling rigs and surrounding infrastructure, interrupt production, and delay exploration and development programs. In 2005, hurricanes reduced our production by approximately 6,000 boe/d before royalties. Although we received minor damage at two of our facilities, by year end we were producing at 92% of our full potential. We expect to be back to full production by mid 2006. We carry property and business interruption insurance to mitigate losses caused by adverse weather.

At year end, we had proved reserves of 90 mmboe before royalties (77 mmboe after royalties) representing about 11% of Nexen's total proved oil and gas and Syncrude reserves. Our production and reserves in the Gulf are primarily concentrated in two deep-water and five shallow-water fields. We operate most of this production.

Deep-Water Production

Our deep-water production comes from our 100%-operated Aspen field and 30% non-operated Gunnison field. Aspen is on Green Canyon Block 243 in 3,150 feet of water. The project was developed using sub-sea wells tied back to the Shell-operated Bullwinkle platform 16 miles away. Production began in December 2002, and we achieved payout on our full investment in Aspen in January 2005. Our share of 2005 production before royalties was approximately 14,300 boe/d (13,000 after royalties). Production declined during the year because of increased water cuts. In 2006, we plan to drill another development well to access potential stranded reserves.

Gunnison is in 3,100 feet of water, and includes Garden Banks Blocks 667, 668 and 669. Gunnison began production in December 2003 through our truss SPAR platform that can handle 40,000 bbls/d of oil and 200 mmcf/d of gas. We achieved payout on Gunnison in December 2005, just two years after first production. In 2005, we tied in one development well, and our share of production before royalties was approximately 9,700 boe/d (8,500 after royalties). Our Gunnison SPAR production facility has excess capacity, leaving room for growth from exploration and processing of third-party volumes. In 2006, we plan to complete and tie-in our 15% non-operated 2004 Dawson Deep discovery to the Gunnison SPAR.


Discoverer Spirit drill ship at Knotty Head

Gunnison and Aspen both achieved payout in just over two years after first production.

Shallow-Water Production

Our shelf producing assets are offshore Louisiana, primarily in five 100%-owned fields: Eugene Island 18, Eugene Island 255/257/258/259, Eugene Island 295, Vermilion 302/321, and Vermilion 76 (consisting of Blocks 65, 66 and 67). We continue to exploit these assets and look for other opportunities on the shelf. Most of our 2005 shelf activities focused on development drilling at Vermilion 76 and 321.

Exploration and Undeveloped Assets

In 2005, our exploration program produced strong results with a potentially significant discovery at Knotty Head and several other smaller discoveries. Our undeveloped discoveries include:

Well	Interest (%)	Operator Status	Comments
Anduin	50	operated	appraisal drilling planned in 2006
Big Bend	50	non-operated	expected to complete the well in 2007
Dawson Deep	15	non-operated	expected to begin producing in 2006
Knotty Head	25	operated	appraisal drilling ongoing in 2006
Wrigley	50	non-operated	expected to begin producing in 2006
Tobago	10	non-operated	expected to begin producing in 2009 or 2010

During the year, we drilled dry holes at Castleton and Vrede and increased our deep-water undeveloped land position by 95 blocks to over 240 blocks. We expect this acreage and future exploration opportunities to position us well for continued growth. In 2006, we plan to tie-in our 2004 Wrigley discovery to a third-party facility and drill appraisal wells at Knotty Head and Anduin. We also plan to drill eight exploration wells (five in the deep water and three in the deep shelf). Wells currently drilling with results expected in the first half of 2006 include Pathfinder and the Knotty Head sidetrack. We have drilling rigs secured for the majority of our 2006 drilling program and are actively working with partners to find rigs for the remainder. We recently committed to a deep-water drilling contract, which provides us with access to a new-build fifth generation dynamically positioned semi-submersible drilling rig for two years over a three-and-a-half year period. We expect this new rig to be available in mid 2009.

We have a potentially significant discovery at Knotty Head.

Fiscal Terms

Royalty rates on our US production average 17% for shallow-water volumes and 10% for deep-water volumes. The fiscal terms are attractive, as we qualify for royalty relief at our deep-water Aspen and Gunnison fields on the first 87.5 mmboe of production. However, we are subject to royalties at Gunnison if annual commodity prices are higher than threshold prices set by the US Department of the Interior's Minerals Management Service. In 2005, commodity prices exceeded these thresholds, and we were subject to a 12.5% royalty at Gunnison. Royalties on other Gulf and state-water properties range from 12.5% to 25%. US taxable income is subject to federal income tax of 35% and state taxes ranging from 0% to 8%.

Canada

Our strategy in Canada is to bring our new growth developments into production while we maximize value from our established operations. In the third quarter of 2005, we disposed of approximately 18,300 boe/d of production, comprising approximately 60% oil and 40% gas, and realized proceeds of $900 million (after closing adjustments). The assets we retained have upside potential for continued conventional development and enhanced recovery with advancements in extraction technology. During the year, we produced 49,900 boe/d before royalties (39,400 after royalties), which was approximately 21% of Nexen's total production. At year end 2005, proved reserves of 117 mmboe before royalties (101 mmboe after royalties) were approximately 15% of our total proved oil and gas and Syncrude reserves.

In Canada, we are transitioning toward unconventional resources, including oil sands, CBM and EOR.

Our remaining Canadian conventional assets comprise heavy oil in east-central Alberta and west-central Saskatchewan, and natural gas near Calgary and in southern Alberta and Saskatchewan. We operate most of our producing properties and hold 1.1 million net acres of undeveloped land across Western Canada. These assets provide predictable production volumes and earnings while we advance the following initiatives for future growth:

- Athabasca oil sands—to produce and upgrade bitumen into synthetic crude;
- enhanced oil recovery (EOR)—to increase recovery in our heavy oil fields; and
- coal bed methane (CBM)—to extract natural gas primarily from Upper Mannville coals.

In 2005, we invested $1,054 million in Canada, $776 million in these growth initiatives. In 2006, we plan to invest approximately $1,170 million, $800 million in these initiatives.

Athabasca Oil Sands

Our oil sands strategy is to economically develop our bitumen resource in phases to provide low-risk, stable, future growth.

The Athabasca oil sands in northeast Alberta is a key growth area for Nexen. Our strategy is to economically develop our bitumen resource in phases to provide low-risk, stable, future growth. Our Long Lake project involves integrating bitumen production with field upgrading technology to produce a premium synthetic crude oil that significantly reduces our need to purchase natural gas. It also includes our 7.23% investment in the Syncrude oil sands mining operation.

Long Lake Project

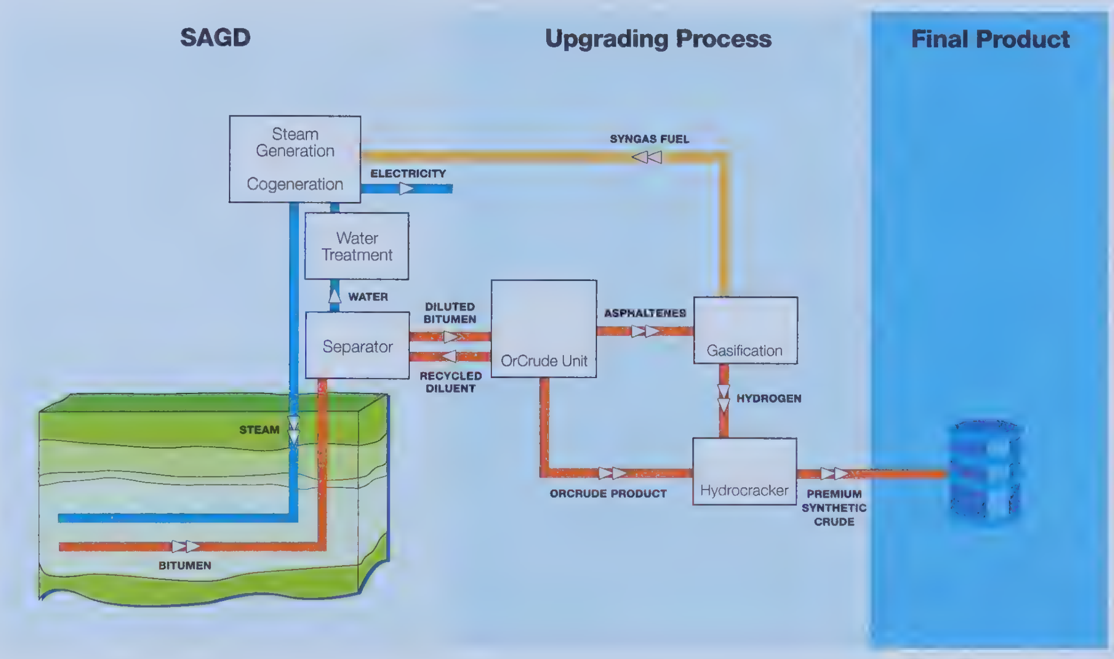
In 2001, we formed a 50/50 joint venture with OPTI Canada Inc. (OPTI) to develop the Long Lake property using steam-assisted-gravity-drainage (SAGD) for bitumen production and field upgrading using the proprietary OrCrude™ process. OrCrude™ is a technology to which OPTI has the exclusive Canadian

license. We acquired the exclusive right to use this technology, with OPTI, within approximately 100 miles of Long Lake, and the right to use the technology independently elsewhere in the world.

We operate the Long Lake lease and are responsible for constructing, developing and operating the SAGD project. OPTI will design, construct and operate the upgrader. We share equally in all project production and operating and capital costs.

SAGD and Upgrader Integration

SAGD involves drilling two parallel horizontal wells, generally between 2,300 and 3,300 feet long, with about 16 feet of vertical separation. Steam is injected into the shallower well, where it heats the bitumen that then flows by gravity to the deeper producing well. The OrCrude™ technology, using distillation, solvent de-asphalting and thermal cracking, separates the produced bitumen into partially upgraded sour crude oil and liquid asphaltenes. By coupling the OrCrude™ process with commercially available hydrocracking and gasification technologies, sour crude is upgraded to light (39° API) premium synthetic sweet crude oil, and the asphaltenes are converted to a low-energy, synthetic fuel gas. This gas is available as a low-cost fuel source, and as a source for hydrogen required in the hydrocracker. The gas will also be burned in a co-generation plant to produce steam for the SAGD operations and for electricity to be used on-site and sold to the electric grid. The energy conversion efficiency for our Long Lake upgrader is about 90% compared to 75% for a typical bitumen-fed coker, which provides us with a 50% margin advantage.



Our Strategic Advantage

Our SAGD and upgrading integration enables us to overcome three main economic hurdles of SAGD bitumen production: 1) the high cost of natural gas; 2) the cost of diluent; and 3) the realized price of bitumen. With synthetic gas from the asphaltenes as a fuel source, we have little need to purchase additional natural gas. With the upgrading facilities on site, expensive diluent is not required to transport the bitumen to market. And, by upgrading the bitumen into a highly desirable refinery feedstock or diluent supply, the end product commands light-sweet crude oil premium pricing.

Project Milestones and Costs

The Long Lake project is on time and on budget. It received regulatory approval in 2003 and Nexen Board approval in 2004. Field construction on the SAGD and upgrader facilities began in 2004. In 2005, we continued module and site construction and completed drilling 78 SAGD well-pairs. Detailed engineering and purchasing of major equipment is substantially complete, with pricing largely as expected. Module construction of the SAGD is 87% complete, and site construction is 43% complete. Module construction of the upgrader is 64% complete and site construction is 32% complete. Approximately

Long Lake pilot project

Long Lake is on time and on budget with synthetic crude oil production expected on stream in 2007.

Our integrated upgrading strategy enables us to upgrade bitumen into high-value premium synthetic crude.

69% of the project's total costs are committed. The major remaining cost uncertainty relates to labour access and productivity. First steam injection is scheduled to begin in late 2006, with upgrader start-up scheduled in the second half of 2007. We expect peak gross synthetic crude oil production to reach about 60,000 bbls/d before royalties and be maintained over the project's life, estimated at 40 years, by periodically drilling additional SAGD well-pairs.

Combined SAGD, cogeneration and upgrading operating costs are expected to average between \$11/bbl and \$13/bbl, substantially lower than coking upgrading. In 2005, we invested \$743 million at Long Lake and expect to invest approximately \$650 million in 2006. Total project costs are estimated at \$3.8 billion (\$1.9 billion our share), which includes \$250 million (\$125 million our share) to increase the capability of the steam generating facility to ensure adequate bitumen supply as we fully develop the reservoir. This expansion will enable us to operate at a steam oil ratio of up to 3.3. In optimizing the value from the project, we will also construct a facility to concentrate soot produced by the gasifier and thereby reduce disposal costs. This facility is expected to cost approximately \$110 million (\$55 million our share). We expect ongoing capital to average between \$2/bbl and \$4/bbl. The capital costs of producing and upgrading bitumen using this technology are comparable to those for surface mining and coking upgrading on a barrel-of-daily production basis.

Long Lake SAGD slant drilling rig

We have not yet recognized any proved bitumen reserves for Long Lake.

Reserves Recognition

Under SEC rules and regulations, we are required to recognize bitumen reserves rather than the upgraded premium synthetic crude oil that we will produce and sell. The economic recoverability of bitumen reserves is sensitive to natural gas prices, diluent costs and light/heavy differentials, risks that our project has been designed to eliminate. At December 31, 2005 and 2004, these factors made bitumen production uneconomic and, therefore, we did not recognize any proved bitumen reserves. Under Canadian standards, we would be permitted to recognize 200 mmbbls of high-value proved synthetic reserves before royalties (198 mmbbls after royalties) for our Long Lake project.

By duplicating Long Lake in phases, we plan to increase our synthetic crude oil production to 120,000 bbls/d by 2016.

Future Phases

We have 214,000 net acres of bitumen-prone lands in the Athabasca region and plan to continue acquiring more. We plan to continue developing our bitumen lands in a phased manner using our integrated upgrading strategy. In 2005, we announced our plan to duplicate Long Lake by developing Phase 2. In 2006, we will invest approximately \$100 million in additional drilling, seismic and engineering to develop our leases and advance regulatory applications for future phases. Phase 2 SAGD production is expected to be on stream by late 2010 with upgrader start-up by the second half of 2011, followed by additional phases every two years or so. Each subsequent phase will leverage the knowledge and experience gained from successfully developing Long Lake and be similar in size and design to Long Lake. By keeping the core team in place and repeating and improving on existing designs and implementation plans, we expect to gain efficiencies in engineering, modular fabrication and on-site construction. We also anticipate enhanced operating efficiencies as we can train and move people easily between the various plants.

Heavy Oil

Approximately 54% of our Canadian production is heavy oil. Heavy oil is characterized by high specific gravity or weight and high viscosity or resistance to flow. Because of these features, heavy oil is more difficult and expensive to extract, transport and refine than other types of oil. Heavy oil also yields a lower price relative to light oil, as a smaller percentage of high-value petroleum products can be refined from heavy oil.

Our heavy oil operations are in east-central Alberta and west-central Saskatchewan. To maximize heavy oil returns, it is important to manage finding, development and operating costs. Our large production base and existing infrastructure are advantageous to us in managing these costs. In 2006, we plan to continue exploiting our existing fields through drilling and optimizing operations.

Enhanced Oil Recovery

Heavy oil reservoirs typically have lower recovery factors than conventional oil reservoirs, leaving substantial amounts of oil in the ground. This creates an opportunity to increase recovery factors by applying

new technology. We are continuing to research various technologies to enhance our heavy oil recovery with ongoing pilot projects in west-central Saskatchewan.

Natural Gas

Approximately 46% of our Canadian production is natural gas produced primarily from shallow sweet reservoirs in southern Alberta and Saskatchewan and from deep sour gas reservoirs near Calgary.

Shallow gas is natural gas produced from shallow sand formations yielding low-pressure sweet gas. In general, shallower gas targets are cheaper to drill and develop, but have relatively smaller reserves and lower productivity per well. Sour gas is natural gas that contains hydrogen sulfide. We have been producing sour natural gas from our Balzac field northeast of Calgary since 1961. This sour gas is processed through our operated Balzac plant.

CBM pumpjack at Corbett

Coal Bed Methane

CBM is commonly referred to as an unconventional form of natural gas because it is primarily stored through adsorption by coal in coal deposits rather than in the pore space of the rock like most conventional gas. The gas is released in response to a drop in reservoir pressure. If the coal deposit is water saturated, water generally needs to be extracted to reduce the pressure and allow gas production to occur. If the coal does not produce water and is "dry", gas will be produced from initial development. Water-producing CBM wells in the United States generally show increasing gas production rates for a period of approximately one to three years before gas rates begin to decline.

Our CBM pilot at Corbett in the Fort Assiniboine area of central Alberta has established techniques to produce natural gas from water saturated Upper Mannville coals. These coals are generally deeper than the Horseshoe Canyon "dry coal" play which is also being commercially developed in Alberta. We established commerciality of CBM production from the Mannville coals in 2005 by applying horizontal well technology. Commercial production rates and reduced de-watering time has enabled us to confidently develop these coals.

In 2005, we approved commercial CBM developments at Corbett, Doris and Thunder in the Fort Assiniboine area. At the end of 2005, we held more than 600 net sections of land in Alberta with CBM potential, some of which overlay existing conventional producing lands. We have also established positions in other prospective CBM areas of Alberta. In 2006, we plan to invest $150 million to develop 115 gross (53 net) sections using single and multi-leg horizontal wells.

We are developing the first commercial CBM project in the Mannville coals.

In addition to our development at Fort Assiniboine, we will continue to evaluate other Mannville and Horseshoe Canyon CBM prospects and pursue new CBM opportunities in 2006. In 2005, we invested approximately $83 million in CBM to commence commercial development at Corbett, Thunder and Doris and build and evaluate our CBM acreage position.

Fiscal Terms

In Canada, we pay royalties ranging from 15% to 40% on production from lands owned by the federal and provincial governments. Some provinces also impose taxes on production from lands where they do not own the mineral rights. The Saskatchewan government assesses a resource surcharge on gross Saskatchewan resource sales that are subject to crown royalties of 3.6% that is reduced to 2.0% for wells completed after October 1, 2002.

Profits earned in Canada from resource properties are subject to federal and provincial income taxes. In 2003, legislation was introduced to reduce the federal corporate income tax rate on income from Canadian oil and gas activities from 28% to 21% by 2007. Canadian entities are also subject to capital taxes.

For our oil sands projects, we will pay royalties based on bitumen production, which includes a 1% royalty on gross revenue until all costs have been recovered at which time the royalty reverts to 25% on net revenue. With the combination of low royalties, our operating cost advantage and a premium product, our oil sands financial returns are expected to be attractive.

Middle East—Yemen

Yemen has been our most significant international region since we first began production at Masila in 1993. We operate the country's largest oil project and have developed excellent relationships with the government and local communities. Our success and reputation in Yemen open doors elsewhere in the Middle East and around the world.

Our strategy is to maximize the value from our existing blocks, while we continue to search for new fields in deeper horizons. We have two producing blocks: Masila (Block 14) and East Al Hajr (Block 51). In 2005, we produced 112,700 bbls/d of oil before royalties (60,600 after royalties), representing approximately 39% of 2005 cash flow.

Proved reserves of 105 mmboe before royalties (59 mmboe after royalties) comprise approximately 13% of Nexen's total proved oil and gas and Syncrude reserves.

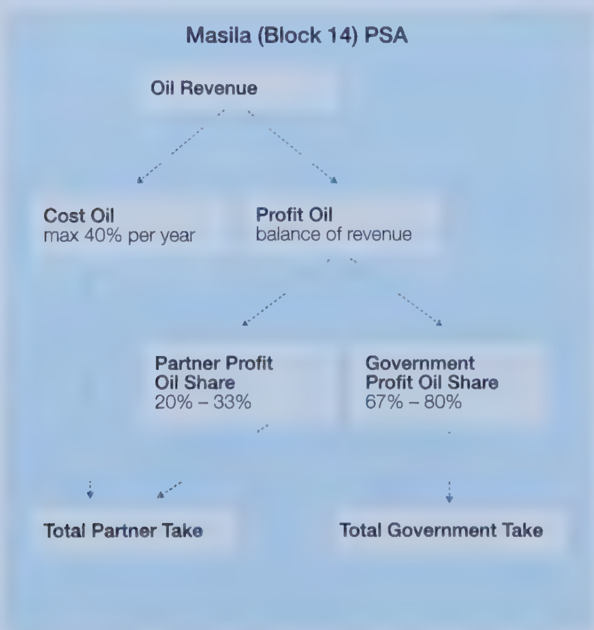
Masila Block (Block 14)

Although our Masila fields have matured, we expect to generate approximately 33% of the total project cash flow from the remaining proved reserves.

We have a 52% working interest in and operate the Masila project. Our share of 2005 production was 87,100 bbls/d before royalties (43,200 after royalties). After more than 10 years of growth, our Masila fields have matured, but significant value still remains. As a result of the Production Sharing Agreement (PSA) terms that govern Masila production, we still expect to generate approximately 33% of the total project cash flow from the remaining proved reserves.

The first successful Masila exploratory well was drilled at Sunah in 1990, with additional discoveries quickly following at Heijah and Camaal. Initial production began in July 1993, with the first lifting of oil in August 1993. Masila Blend oil averages 31° API at very low gas-oil ratios. Most of the oil is produced from the Upper Qishn formation, but we also produce from deeper formations including the Lower Qishn, Upper Saar, Saar, Madbi, Basal Sand and Basement formations.

Production is collected at our Central Processing Facility (CPF) where water is separated for reinjection and oil is pumped to the Ash Shihr export terminal and shipped to customers primarily in Asia.



We are managing the pace of our drilling program to ensure we recover the remaining reserves in the most efficient, cost-effective manner. In 2006, we plan to invest approximately \$95 million to drill approximately 30 wells and test deeper horizons where we have had recent success.

The PSA governing Masila production was signed in 1987 between the Government of Yemen and the Masila joint venture partners (Partners), including Nexen. Under the PSA, we have the right to produce oil from Masila into 2011 and to negotiate a five-year extension. Production is divided into cost recovery oil and profit oil. Cost recovery oil provides for the recovery of all exploration, development,

and operating costs that are funded by the Partners. Costs are recovered from a maximum of 40% of production each year, as follows:

Costs	Recovery
Operating	100% in year incurred
Exploration	25% per year for 4 years
Development	16.7% per year for 6 years

The remaining production is profit oil that is shared between the Partners and the Government and is calculated on a sliding scale based on production. The Partners' share of profit oil ranges from 20% to 33%. The structure of the agreement moderates the impact on Partners' cash flows during periods of low prices, as we recover our costs first and then share any remaining profit oil with the Government. At current production, the Government is entitled to approximately 72% of the profit oil, which includes a component for Yemen income taxes payable by the Partners at a rate of 35%. In 2005, the Partners' share of Masila production, including recovery of past costs, was approximately 37%.


Ash Shihr Terminal

East Al Hajr Block (Block 51)

We have an 87.5% working interest and operate Block 51. This block is governed by a PSA between the Government of Yemen and the Partners: The Yemen Company (TYCO) (12.5% carried working interest) and Nexen (87.5% working interest). Under the PSA, TYCO has no obligation to fund capital or operating expenditures. For purposes of accounting and recording of reserves, we have determined TYCO's 12.5% participating interest is a royalty interest, and that our effective interest is 100%. We recognize both the Government's share and TYCO's share of profit oil under the PSA as royalties and taxes consistent with our treatment of our Masila operations. The PSA expires in 2023, and we have the right to negotiate a five-year extension. Under the terms of the PSA, the Partners pay a royalty ranging from 3% to 10% to the Government depending on production volumes. The remaining production is divided into cost recovery oil and profit oil. Cost recovery oil provides for the recovery of all of the project's exploration, development and operating costs, funded solely by Nexen. Costs are recovered from a maximum of 50% of production each year after royalties, as follows:

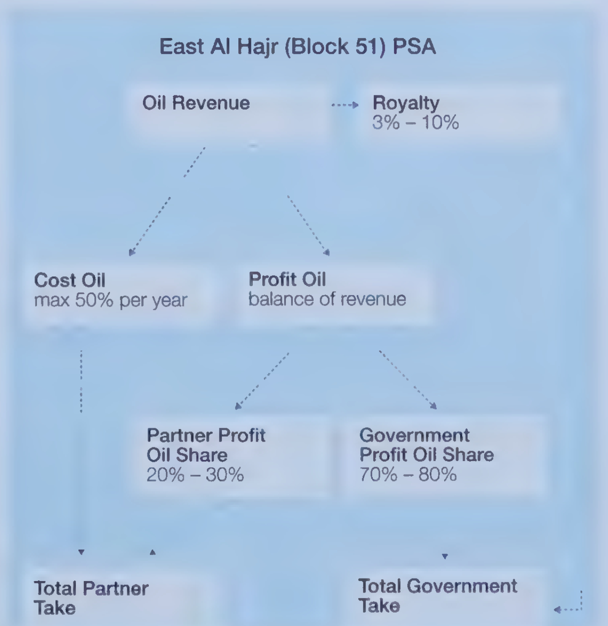
In its first full year of operation, Block 51 averaged 25,600 bbls/d in 2005.

Costs	Recovery
Operating	100% in year incurred
Exploration	75% per year, declining balance
Development	75% per year, declining balance

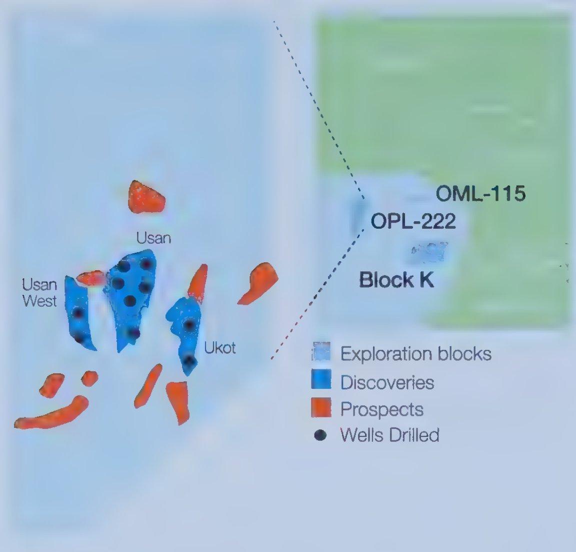
The remaining production is profit oil that is shared between the Partners and the Government on a sliding scale based on production rates. The Partners' share of profit oil ranges from 20% to 30%. The Government's share of profit oil includes a component for Yemen income taxes payable by the Partners at a rate of 35%. In 2005, the Partners' share of Block 51 production, including recovery of past costs, was approximately 61%.

The first successful exploratory well was drilled at BAK-A in 2003, with BAK-B discovered shortly after. Block 51 development began in 2004 and includes a CPF, gathering system and a 22-km tieback to our Masila export pipeline. Early production began in November 2004 with 2005 production of 25,600 bbls/d before royalties (17,400 bbls/d after royalties).

In 2005, we drilled four exploration wells on the block that were abandoned. In 2006, we plan to invest approximately $100 million to drill 17 development wells and continue exploring with three exploration wells.



Offshore West Africa



Offshore West Africa is a growing core area where we already have discoveries. It offers prolific reservoirs and multiple opportunities to invest in this oil-rich region. Our strategy here is to explore and develop our portfolio for medium- to long-term growth.

In 2005, we invested $47 million of capital offshore West Africa and expect to invest approximately $55 million in 2006.

Nigeria

Block OPL-222

In 1998, we acquired a 20% non-operated interest in Block OPL-222, which includes 448,000 acres and is approximately 50 miles offshore in water depths ranging from 600 to 3,500 feet. The ongoing appraisal of the block indicates significant hydrocarbon accumulations based on the drilling results outlined below:

Appraisal of Usan is complete, and a preliminary field development plan is awaiting approval from the Nigerian government.

Year	Well	Location	Results
1998	Ukot-1	Ukot field discovery well	encountered three oil-bearing intervals and flowed at restricted rate of 13,900 bbls/d from two intervals
2002	Usan-1	Usan field discovery well	encountered several oil-bearing intervals and flowed at restricted rate of 5,000 bbls/d from one interval
2003	Usan-2	3 km west of discovery	appraised up-dip portion of the fault block
2003	Usan-3	2 km northwest of discovery	appraised separate fault block and flowed at restricted rate of 5,600 bbls/d from one interval
2003	Ukot-2	3.5 km south of discovery	encountered three oil-bearing intervals
2003	Usan-4	5 km south of discovery	flowed at restricted rate of 4,400 bbls/d from first interval and 6,300 bbls/d from second interval
2004	Usan-5	6 km west of discovery	sampled oil in several intervals
2004	Usan-6	4 km south of Usan-5	flowed at restricted rate of 5,800 bbls/d from one interval
2005	Usan-7	9 km southwest of discovery	confirmed an eastern extension of the field
2005	Usan-8	3 km southwest of discovery	confirmed an eastern extension of the field

The Usan-7 and Usan-8 appraisal wells were successfully drilled during the year. Appraisal of this field is now complete, and a preliminary field development plan has been submitted to Nigerian governmental agencies for approval. The plan features a multi-well development of Usan connected to a two-million-barrel floating production, storage and offloading vessel (FPSO) by subsea flowlines and risers. The peak design capacity of the FPSO is 160,000 bbls/d.

In 2005, we drilled the deep-water Efere well. This well was unsuccessful and the capital costs were expensed.

Block OML-115

The Nigerian Government formally approved the Deed of Assignment for OML-115 in December 2003, which assigned us a 40% interest in the block. In 2004, we drilled a well on the Ameena prospect and did not find hydrocarbons. In 2006, we plan to conduct geological and geophysical studies to further evaluate the block.

Block OML-109—Ejulebe

Ejulebe production averaged 200 bbls/d for the year. In June, we sold our assets and terminated our contractual interest in this block.

Equatorial Guinea—Block K

In 2003, we acquired a 25% operated interest in Block K, a deep-water block located 100 km offshore Equatorial Guinea. This interest was later increased to 50%. In 2004 and 2005, we drilled two exploration wells and found non-commercial quantities of hydrocarbons. In 2006, we plan to make a recommendation to the partners on future participation in this block.


Drilling rig on OPL-222, offshore Nigeria

Other International

Colombia

Boqueron Block—Guando

In 2000, we made our first discovery at Guando on our 20% non-operated Boqueron Block. Boqueron is in the Upper Magdalena Basin of central Colombia, approximately 45 km southwest of Bogota. Our share of 2005 production averaged 5,400 bbls/d before royalties (5,000 after royalties), about 2% of Nexen's total production.

Production from Guando is subject to a 5% to 25% royalty depending on daily production. The corporate income tax rate is 38.5%.

Exploration Blocks

We are assessing potential drilling opportunities on our interests in three other exploration blocks in the Upper Magdalena Basin. Villarrica was acquired in 2000, El Queso in 2003 and Boqueron Deep in 2003. In 2005, we relinquished the Villarrica Block and acquired the Villarrica Norte Block under improved fiscal terms. In 2006, we plan to drill three exploration wells.

Australia—Buffalo

Field abandonment began in November 2004 and was completed in 2005.

RESERVES, PRODUCTION AND RELATED INFORMATION

In addition to the tables below, we refer you to the Supplementary Data in Item 8 of this Form 10-K for information on our oil and gas producing activities. Nexen has not filed with nor included in reports to any other United States federal authority or agency, any estimates of total proved crude oil or natural gas reserves since the beginning of the last fiscal year.

Net Sales by Product from Continuing Oil and Gas Operations (including Syncrude)

(Cdn$ millions)	2005	2004	2003
Conventional Crude Oil and Natural Gas Liquids (NGLs)	2,438	1,697	1,449
Synthetic Crude Oil	397	321	240
Natural Gas	671	534	547
Total	**3,506**	**2,552**	**2,236**

Crude oil and NGLs represent about 81% of our oil and gas net sales.

Crude oil (including synthetic crude oil) and natural gas liquids represent approximately 81% of our oil and gas net sales, while natural gas represents the remaining 19%.

Masila block, Yemen

Sales Prices and Production Costs (excluding Syncrude)

	Average Sales Price [1]			Average Production Cost [1]		
	2005	2004	2003	2005	2004	2003
Crude Oil and NGLs (Cdn$/bbl)						
Yemen	62.07	47.59	39.45	6.75	5.64	4.37
Canada [2]	40.51	36.60	32.37	14.01	11.76	10.00
United States	57.63	46.60	37.68	7.33	6.09	5.08
United Kingdom	60.55	46.81	–	14.90	8.26	–
Australia [2]	–	51.22	43.14	–	35.73	20.21
Other Countries	59.96	43.07	38.22	6.08	4.09	9.01
Natural Gas (Cdn$/mcf)						
Canada [2]	7.51	5.76	5.64	0.95	0.85	0.65
United States	10.56	7.89	8.16	1.22	1.02	0.89
United Kingdom	7.86	8.28	–	2.48	–	–

Notes:
1 Sales prices and unit production costs are calculated using our working interest production after royalties.
2 Includes results of discontinued operations. (See Note 14 to our Consolidated Financial Statements.)

Producing Oil and Gas Wells

	2005					
	Oil		Gas		Total	
(number of wells)	Gross [1]	Net [2]	Gross [1]	Net [2]	Gross [1]	Net [2]
United States	198	89	195	135	393	224
Yemen	400	220	–	–	400	220
United Kingdom	33	14	–	–	33	14
Canada	2,321	1,625	2,457	2,161	4,778	3,786
Colombia	79	17	–	–	79	17
Total	**3,031**	**1,965**	**2,652**	**2,296**	**5,683**	**4,261**

Notes:
1 Gross wells are the total number of wells in which we own an interest.
2 Net wells are the sum of fractional interests owned in gross wells.

Oil and Gas Acreage

	2005					
	Developed		Undeveloped [1]		Total	
(thousands of acres)	Gross	Net	Gross	Net	Gross	Net
United States	183	103	1,445	606	1,628	709
Yemen [2]	50	29	756	628	806	657
Nigeria [2,3]	–	–	510	114	510	114
Equatorial Guinea	–	–	1,106	553	1,106	553
Canada	702	531	2,120	1,109	2,822	1,640
Colombia [4]	1	–	604	463	605	463
United Kingdom	83	27	1,851	963	1,934	990
Total	**1,019**	**690**	**8,392**	**4,436**	**9,411**	**5,126**

Notes:
1 Undeveloped acreage is considered to be those acres on which wells have not been drilled or completed to a point that would permit production of commercial quantities of crude oil and natural gas regardless of whether or not such acreage contains proved reserves.
2 The acreage is covered by production sharing contracts.
3 The acreage is covered by a joint venture agreement.
4 The acreage is covered by an association contract.

Drilling Activity

	2005						
	Net Exploratory			Net Development			Total
(number of net wells)	Productive	Dry Holes	Total	Productive	Dry Holes	Total	
United States	–	0.6	0.6	7.2	1.0	8.2	8.8
United Kingdom	0.5	2.1	2.6	1.5	–	1.5	4.1
Yemen	0.5	4.6	5.1	33.0	1.6	34.6	39.7
Nigeria	0.4	0.2	0.6	–	–	–	0.6
Canada	32.2	8.0	40.2	198.9	0.5	199.4	239.6
Colombia	–	–	–	1.8	–	1.8	1.8
Equatorial Guinea	–	0.5	0.5	–	–	–	0.5
Total	**33.6**	**16.0**	**49.6**	**242.4**	**3.1**	**245.5**	**295.1**

	2004						
	Net Exploratory			Net Development			Total
(number of net wells)	Productive	Dry Holes	Total	Productive	Dry Holes	Total	
United States	0.3	1.8	2.1	11.0	1.0	12.0	14.1
United Kingdom	–	–	–	–	–	–	–
Yemen	–	2.0	2.0	37.3	0.5	37.8	39.8
Nigeria	0.4	1.0	1.4	–	–	–	1.4
Canada	13.4	1.0	14.4	202.9	–	202.9	217.3
Colombia	–	–	–	7.0	–	7.0	7.0
Equatorial Guinea	–	0.5	0.5	–	–	–	0.5
Total	**14.1**	**6.3**	**20.4**	**258.2**	**1.5**	**259.7**	**280.1**

	2003						
	Net Exploratory			Net Development			Total
(number of net wells)	Productive	Dry Holes	Total	Productive	Dry Holes	Total	
United States	–	0.5	0.5	8.3	0.1	8.4	8.9
Yemen	8.0	1.0	9.0	49.0	–	49.0	58.0
Nigeria	0.6	–	0.6	–	–	–	0.6
Canada	15.4	1.7	17.1	157.7	2.5	160.2	177.3
Colombia	–	1.0	1.0	6.2	–	6.2	7.2
Brazil	–	0.2	0.2	–	–	–	0.2
Total	**24.0**	**4.4**	**28.4**	**221.2**	**2.6**	**223.8**	**252.2**

Wells in Progress

At December 31, 2005, we were drilling 7 wells in the United States (4.0 net), 15 wells in Canada (8.6 net), 4 wells in Yemen (3.0 net), 1 well in Colombia (0.2 net), and 2 wells in the UK (0.8 net).

SYNCRUDE MINING OPERATIONS

Upgrader Syncrude Leases

We hold a 7.23% participating interest in Syncrude Canada Ltd. (Syncrude). This joint venture was established in 1975 to mine shallow oil sands deposits using open-pit mining methods, extract the bitumen from the oil sands and upgrade the bitumen to produce a high-quality, light (32° API), sweet, synthetic crude oil.

The Syncrude operation exploits a portion of the Athabasca oil sands deposit that contains bitumen in the unconsolidated sands of the McMurray formation. Ore bodies are buried beneath 50 to 150 feet of overburden, have bitumen grades ranging from 4 to 14 percent by weight and ore bearing sand thickness of 100 to 160 feet.

Syncrude's operations are on eight leases (10, 12, 17, 22, 29, 30, 31, and 34) covering 258,000 hectares, 40 km north of Fort McMurray in northeast Alberta.

Syncrude mines oil sands at three mines: Base, North, and Aurora North. These locations are readily accessible by public road. At the Base Mine (lease 17), a dragline, bucket-wheel reclaimers, and belt conveyors are used for mining and transporting oil sands. In the North Mine (leases 17 and 22) and in the Aurora North Mine (leases 10, 12, and 34), a truck-and-shovel and hydro-transport system is used.

The extraction facilities, which separate bitumen from oil sands, are capable of processing more than 260 million tons of oil sands per year and about 146 mmbbls of bitumen per year. To extract bitumen, the oil sands are mixed with water to form a slurry. Air and chemicals are added to separate bitumen from the sand grains. The process at the Base Mine uses hot water, steam, and caustic soda to create a slurry, while at the North Mine and the Aurora North Mine, the oil sands are mixed with warm water to produce a slurry.

The extracted bitumen is fed into a vacuum distillation tower and two cokers for primary upgrading. The resulting products are then separated into naphtha, light gas oil, and heavy gas-oil streams. These streams are hydrotreated to remove sulphur and nitrogen impurities to form light, sweet, synthetic crude oil. Sulphur and coke, which are by-products of the process, are stockpiled for possible future sale. In 2005, the upgrading process yielded 0.85 barrels of synthetic crude oil per barrel of bitumen.

The high quality of Syncrude's synthetic crude oil typically means it is sold at a premuim to WTI.

The high quality of Syncrude's synthetic crude oil typically means it is sold at a premium to WTI. In 2005, about 49% of the synthetic crude oil was sold to Edmonton area refineries, and the remaining 51% was sold to refineries in Eastern Canada and the mid-Western United States.

Electricity is provided to Syncrude from two generating plants: a 270 MW plant and an 80 MW plant. Both plants are at Syncrude and owned by the Syncrude participants.

Since operations started in 1978, Syncrude has shipped more than 1.6 billion barrels of synthetic crude oil to Edmonton, Alberta, by Alberta Oil Sands Pipeline Ltd. The pipeline was expanded in 2004 to accommodate increased Syncrude production.

At year-end 2005, our total investment in the property, plant and equipment, including surface mining facilities, transportation equipment, and upgrading facilities, was approximately $1.2 billion. Based on development plans, our share of future expansion and equipment replacement costs over the next 35 years is expected to be about $1.5 billion.

In 1999, the Alberta Energy and Utilities Board (AEUB) extended Syncrude's operating license for the eight oil sands leases through to 2035. The license permits Syncrude to mine oil sands and produce

synthetic crude oil from approved development areas on the oil sands leases. The leases are automatically renewable as long as oil sands operations are ongoing or the leases are part of an approved development plan. All eight leases are included in a development plan approved by the AEUB. There were no known commercial operations on these leases prior to the start-up of operations in 1978.

Syncrude pays a royalty to the Province of Alberta. Subsequent to 1987, this royalty was equal to 50% of Syncrude's deemed net profits after deduction of capital expenditures. In 1995, the Province of Alberta announced generic royalty terms for new oil sands projects that provide for a royalty rate of 25% on net revenues after all costs have been recovered, subject to a minimum 1% gross royalty. In 1997, the Province of Alberta and the Syncrude owners agreed to move to the generic royalty terms when the total of all allowed capital costs incurred after December 31, 1995 equalled $2.8 billion (gross). That total was surpassed at the end of 2001. In 2005, Syncrude was subject to the minimum 1% gross royalty. In 2006, we expect to complete full recovery of allowed capital costs and, as a result, we expect Syncrude royalties to be assessed at 25% of net revenues.

In 1999, the AEUB approved an increase in Syncrude's production capacity to 465,700 bbls/d. At the end of 2001, Syncrude had increased its synthetic crude oil capacity to 246,500 bbls/d with the development of the Aurora North Mine, which involved extending mining operations to a new location about 25 miles north of the main Syncrude site. In 2001, the Syncrude owners approved the third stage of the Syncrude expansion, which will increase capacity to 360,000 bbls/d in 2006. With higher engineering, manufacturing and construction costs, the estimated costs of the Stage 3 expansion have increased from initial estimates of $4.1 billion to $8.4 billion. Nexen's share of the project costs is $600 million, of which $568 million had been incurred by year end 2005. Activities in 2006 are focused on completion and start-up of the Stage 3 expansion and base plant maintenance. Our share of capital spending in 2006 is expected to be $80 million.

Syncrude's Stage 3 expansion was substantially complete at year end and will add 8,000 bbls/d of production capacity to us in 2006.

In 2005, Syncrude's production of marketable synthetic crude oil was 214,000 bbls/d. Nexen's share was 15,500 bbls/d before royalties (15,300 bbls/d after royalties).

The following table provides some operating statistics for Syncrude operations:

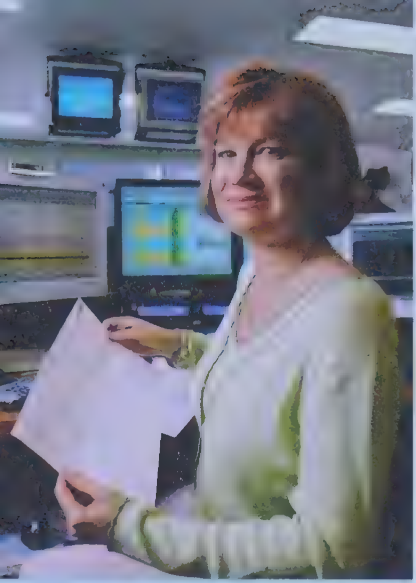
	2005	2004	2003
Total Mined Volume [1]			
Millions of Tons	353	389	380
Mined Volume to Oil Sands Ratio [1]	2.1	2.1	2.3
Oil Sands Processed			
Millions of Tons	169	188	168
Average Bitumen Grade (weight %)	11.1	11.1	11.0
Bitumen in Mined Oil Sands			
Millions of Tons	19	21	18
Average Extraction Recovery (%)	89	87	89
Bitumen Production [2]			
Millions of Barrels	94	103	92
Average Upgrading Yield (%)	85	86	86
Gross Synthetic Crude Oil Shipped [3]			
Millions of Barrels	78	87	77
Nexen's Share of Marketable Crude Oil			
Millions of Barrels Before Royalties	5.7	6.3	5.6
Millions of Barrels After Royalties	5.6	6.1	5.5

Notes:

1 Includes pre-stripping of mine areas and reclamation volumes.

2 Bitumen production in barrels is equal to bitumen in mined oil sands multiplied by the average extraction recovery and the appropriate conversion factor.

3 Approximately 1.2% of the produced synthetic crude oil is used internally at Syncrude. The remaining synthetic crude oil is sold externally.



Employee in our marketing operations

OIL AND GAS MARKETING

Our marketing group sells proprietary and third-party natural gas, crude oil, natural gas liquids and power in certain regional markets where we have built a solid strategic presence. This includes access to transportation, storage and facilities, as well as crude oil and natural gas we produce or acquire. We optimize the margin on our base business by trading around our access to these physical assets when market opportunities present themselves. We use financial and derivative contracts, including futures, forwards, swaps and options for hedging and trading purposes.

Our marketing strategy is to:

- obtain competitive pricing on the sale of our own oil and gas production;
- provide market intelligence in support of our oil and gas operations;
- provide superior customer service to producers and consumers; and
- capitalize on market opportunities through low-risk trading related to our transportation and storage assets.

This strategy aligns with our corporate focus on extracting full value from our assets and provides us with the market intelligence needed to deliver our current and future oil and gas production to market at competitive pricing.

Gas Marketing

The marketing and trading of natural gas is our marketing group's largest revenue stream.

The marketing and trading of natural gas is our marketing group's largest revenue stream. We focus on key regional markets where we have a strategic presence—solid customer relationships, in-depth understanding of the market or established physical trading-based assets. We capture regional opportunities by managing supply, transportation and storage assets for producers and end users. In addition to the fee-for-service income we realize from managing these assets, we generate further revenue by:

- capitalizing on location spreads (differences in prices between market locations) using our transportation assets; and
- capitalizing on time spreads (differences in prices between summer and winter) using our storage assets.

We have offices in key regions including Calgary, Detroit and Houston. Our Calgary office provides a variety of services, including supply, storage, and transportation management as well as netback pool arrangements and other customer services. Our customers include producers and consumers in Western Canada as well as consumers (including utilities) in Eastern Canada, the Northeastern United States and the US mid-continent. Our offices in Detroit and Calgary work together to provide services to our customers. Our presence in Houston has established us in the Gulf Coast region where we have our own production.

We use access to transportation and storage facilities to optimize returns, capitalizing on location and time spreads.

We use our access to transportation and storage facilities to optimize returns for ourselves as well as our customers.

In 2003 and 2004, we grew our asset base by acquiring physical gas purchase and sales contracts, as well as natural gas transportation capacity on favourable terms. This has given us access to new third party gas supply until 2008, pipeline capacity to 2016 and new relationships that have enabled us to negotiate new gas purchase and sales contracts.

Our position as a physical marketer at multiple delivery points in key markets gives us the flexibility to capitalize on time and location spreads. With pipeline capacity, we can move gas from producing regions to take advantage of price differences. At the end of 2005, we held 4 bcf/d of pipeline capacity, primarily between Western Canada and Eastern US. We also use storage capacity to store typically cheaper summer gas in the ground until the winter heating season arrives. We had access to 30 bcf of natural gas storage facilities at the end of the year.

In addition to transportation and storage assets, we hold financial contracts that enable us to capture profits around time and location spreads. The basis risk we assume on these contracts is based on solid fundamental analysis and in-depth knowledge of regional markets. The risk is managed proactively by our product group teams and monitored closely by our risk group, with regular reporting to management and the Board.

Crude Oil Marketing

Our crude oil business focuses on marketing physical crude oil to end-use refiners. The crude oil group markets our own production and more than 500,000 bbls/d of third-party field production to refiners from producing regions where we operate. In addition to physical marketing, we take advantage of quality differentials and time spreads.

Our crude oil business markets physical volumes to end-use refiners and takes advantage of quality differentials and time spreads.

Our North American operations focus on key regions supported by our offices in Calgary and Houston. In Western Canada, our producer services group concentrates on the procurement of a diversified supply base, while our trading team seeks to optimize the mix for sale to refiners. Traditionally, the Chicago and Denver areas have been key markets for our Western Canadian crude, however, recently we have expanded our presence into the US gulf coast. Our deep-water Gulf of Mexico crude oil production has given us the opportunity to expand our presence in that market through our Houston office.

Internationally, we focus on the physical marketing of our Yemen crude oil. In order to meet customer needs, we may occasionally market other regional crude types. In addition to our own crude, we market production for our partners and third parties in the Yemen region. By locating our international crude oil marketing office in Singapore, we are well positioned to serve both the producing region and the Asian refining market. During the year, we added an office in London, in the United Kingdom, to begin maximizing the value of our North Sea production. As Buzzard crude comes on stream in late 2006, we expect to increase our presence in various European markets, ensuring we maximize the value of this production.

Our crude oil marketing group also holds financial contracts that enable us to capture trading profits around time, quality and location spreads. Like gas marketing, the basis risk assumed is based on solid fundamental analysis and proprietary knowledge of regional markets, and it is managed and monitored closely by our risk group.

Power Marketing

Our power marketing group is responsible for optimizing the use of our 100 MW gas-fired, combined-cycle power generation facility at Balzac, Alberta, and for marketing power to larger commercial, industrial and municipal clients in Alberta. With our recent acquisition of a commercial/industrial business in Alberta, we have become the largest supplier of power to the commercial and industrial sectors in the province. Our Balzac facility began operations in 2001. We expect to increase our power generation capacity with a 170 MW co-generation facility at Long Lake in 2007, and through our 70 MW Soderglen wind power project in southern Alberta in 2006. We have a 50% interest in each project.

We are now the largest supplier of power to the commercial and industrial sectors in Alberta.

In 2005, we monetized a portion of our chemicals business through an initial public offering, retaining a 61.4% indirect interest.

Our Brandon plant is the world's largest sodium chlorate plant and one of the lowest cost producers in North America.

CHEMICALS

Sodium Chlorate
Chlor-Alkali

In 2005, we monetized part of our chemicals business through an initial public offering of the Canexus Income Fund. We have retained a 61.4% indirect interest in our chemicals business, and we continue to fully consolidate chemicals in our consolidated financial statements.

Our chemicals business manufactures sodium chlorate and chlor-alkali products (chlorine, caustic soda and muriatic acid) in Canada and Brazil. This production is sold in North and South America, with some sodium chlorate distributed in Asia. Our manufacturing facilities are modern, reliable and strategically located to capitalize on competitive power costs or transportation infrastructure to minimize production and delivery costs. This enables us to have reliable supplies and low costs—key factors for marketing bleaching chemicals.

Electricity is the most significant operating cost in producing sodium chlorate and chlor-alkali products, making up over half our cash costs. Therefore, our current facilities are strategically located to take advantage of economic power sources. Our second highest cost is transportation. Our sales are concentrated mainly in North America and Brazil with a small amount of sodium chlorate sold in Asia. The proximity of our manufacturing plants to major customers and competitive freight rates minimizes our transportation costs. Labour is also a significant manufacturing cost. Approximately 50% of our workforce is unionized with collective agreements in place at all of our unionized plants.

To grow value in our chemicals business, we focus on improving our costs while maintaining market share, building a sustainable North American customer base and capturing new offshore opportunities.

Average Annual Production Capacity

(short tons)	2005	2004	2003
Sodium Chlorate			
North America	446,208	446,617	432,812
Brazil	68,563	68,563	68,563
Total	**514,771**	**515,180**	**501,375**
Chlor-alkali			
North America	356,002	356,002	356,002
Brazil	109,430	109,430	109,430
Total	**465,432**	**465,432**	**465,432**

North America

The North American pulp and paper industry consumes approximately 95% of the continent's sodium chlorate production. We market our sodium chlorate production to numerous pulp and paper mills under multi-year contracts that contain price and volume provisions. Approximately 31% of this production is sold in Canada, 62% in the US, and the rest is marketed offshore.

We are the third-largest manufacturer of sodium chlorate in North America with four Canadian facilities: Nanaimo, British Columbia; Bruderheim, Alberta; Brandon, Manitoba; and Beauharnois, Quebec.

In October 2004, we completed an expansion of our plant in Brandon, Manitoba increasing capacity to 260,000 tonnes per year. This expansion replaced higher-cost capacity idled in 2002 at Taft, Louisiana. Brandon is the world's largest sodium chlorate facility and has one of the lowest cost structures in the industry, significantly enhancing our competitive position in North America. During the year, we closed our plant at Amherstburg, Ontario.

Our chlor-alkali facility at North Vancouver, British Columbia, manufactures caustic soda, chlorine and muriatic acid. Almost all of our caustic soda is consumed by local pulp and paper mills, while our chlorine is sold to various customers in the polyvinyl chloride, water purification and petrochemicals industries, primarily in the United States.

Brazil

We entered Brazil in 1999 by acquiring a sodium chlorate plant and a chlor-alkali plant from Aracruz Cellulose S.A. (Aracruz), the leading manufacturer of pulp in Brazil. The majority of the production is sold to Aracruz under a long-term sales agreement that expires in 2024. This agreement had an initial six-year take-or-pay component that ended in 2005. Most of the chlorine and about 20% of the sodium chlorate production is sold in the merchant market under shorter-term contractual arrangements. In 2002, we completed an expansion at both facilities to meet Aracruz's growing needs. The majority of our electricity needs are supplied by a long-term supply contract in Brazil.

ADDITIONAL FACTORS AFFECTING BUSINESS

See Item 7 of this Form 10-K.

Government Regulations

Our operations are subject to various levels of government controls and regulations in the countries where we operate. These laws and regulations include matters relating to land tenure, drilling, production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax, and foreign trade and investment, that are subject to change from time to time. Current legislation is generally a matter of public record, and we are unable to predict what additional legislation or amendments may be proposed that will affect our operations or when any such proposals, if enacted, might become effective. We participate in many industry and professional associations and monitor the progress of proposed legislation and regulatory amendments.

Environmental Regulations

Our oil and gas and chemical operations are subject to government laws and regulations designed to protect and regulate the discharge of materials into the environment in countries where we operate. We believe our operations comply in all material respects with applicable environmental laws. To reduce our exposure, we apply industry standards, codes and best practices to meet or exceed these laws and regulations. Occasionally, we may conduct activities in countries where environmental regulatory frameworks are in various stages of evolution. Where regulations are lacking, we observe Canadian standards where applicable, as well as internationally accepted industry environmental management practices.

We have an active safety, environment and social responsibility group that ensures our worldwide operations are conducted in a safe, ethical and socially responsible manner. We have developed policies for continuing compliance with environmental laws and regulations in the countries in which we operate.

We have an active safety, environment and social responsibility group that ensures our worldwide operations are conducted in a safe, ethical and socially responsible manner.

Environmental Provisions and Expenditures

The ultimate financial impact of environmental laws and regulations is not clearly known and cannot be reasonably estimated as new standards continue to evolve in the countries in which we operate. We estimate our future environmental costs based on past experience and current regulations. At December 31, 2005, $611 million ($1,471 million, undiscounted) has been provided in our Consolidated Financial Statements for asset retirement obligations for our oil and gas, Syncrude and chemicals facilities. In 2005, we increased our retirement obligations for future dismantlement and site restoration by $210 million primarily from increased drilling and development activities in the Gulf of Mexico, North Sea, Canada and Yemen, general industry cost pressures and more stringent environmental laws and regulations.

In 2005, our capital expenditures for environmental-related matters, including environment control facilities, were approximately $34 million. Our operating expenditures for environmental-related matters were approximately $5 million. In 2006, we estimate these expenditures to be approximately $21 million.

Gulf of Mexico employee on drill ship

EMPLOYEES

We had 3,282 employees on December 31, 2005, of which 301 were employed under collective bargaining schemes. Information on our executive officers is presented in Item 10 of this report.

Item 1A. **Risk Factors**

Refer to pages 62 to 69 for a discussion of our risk factors.

Item 1B. **Unresolved Staff Comments**

There are no unresolved staff comments with the SEC.

Item 3. **Legal Proceedings**

There are a number of lawsuits and claims pending against Nexen, the ultimate results of which cannot be ascertained at this time. Management is of the opinion that any amounts assessed against us would not have a material adverse effect on our consolidated financial position or results of operations. We believe we have made adequate provisions for such lawsuits and claims.

Certain of our US oil and gas operations have received, over the years, notices and demands from the US Environmental Protection Agency (EPA), state environmental agencies, and certain third parties with respect to certain sites seeking to require investigation and remediation under federal or state environmental statutes. In addition, notices, demands, and lawsuits have been received for certain sites related to historical operations and activities in the US for which, although no assurances can be made, we believe that certain assumption and indemnification agreements protect our US operations from any present or future material liabilities that may arise from these particular sites.

On June 25, 2003, a subsidiary of Occidental Petroleum Corporation (Occidental) initiated an arbitration at the International Court of Arbitration of the International Chamber of Commerce (ICC) regarding an Area of Mutual Interest Agreement (Agreement) in Yemen. Pursuant to the Agreement, if Nexen proposed to conduct petroleum development operations within two small areas of Block 51 in Yemen (Heijah/Tawila Extension Lands), then we were to offer Occidental the right to acquire 50% of our interest in those areas. The Agreement expired on March 12, 2003, with Nexen not having proposed any such operations. Subsequent to the Agreement's expiry, we began exploration activities on Block 51, including the Heijah/Tawila Extension Lands and, in December 2003, filed a notice of commercial discovery with the Yemen government. Occidental seeks a claim for declaratory relief under the Agreement, claims compensation for breach of contract (50% of the net profits earned or to be earned from the Heijah/Tawila Extension Lands), plus interest and costs. Given that the agreement expired without Nexen having proposed to conduct petroleum development operations, we believe Occidental's claim is without merit and have vigorously defended our contractual rights. The ICC arbitration hearing with respect to liability took place in San Francisco in July 2005, and we are awaiting the decision of the tribunal. If the tribunal finds that Occidental has a claim under the Agreement, the amount of damages will be determined in the second phase of the arbitration.

In April 2005, a former employee in our US offshore operations made allegations that he tampered with water samples, dumped material overboard and did not report oil sheens. All of these allegations, if true, would be potential violations of the permit and regulations issued under the Federal Clean Water Act and possibly violations of the Federal Oil Pollution Act. In May 2005, Nexen made written disclosure of these allegations to the Dallas Region of the EPA, and on July 15, 2005, we sent a detailed written submission to the EPA. During compliance training that Nexen conducted to address these allegations, Nexen uncovered evidence that it may have discharged material from certain cleaning vessels during routine cleaning. This discharge may have been prescribed under the permit, so this was also disclosed to the EPA on July 27, 2005. The potential penalties range up to US$32,000 per day per violation for civil judicial penalties and up to US$50,000 per day for criminal violations. At this time, it is difficult to determine the type and level of penalties that might be sought by EPA, as the agency has the discretion to seek penalties within

a broad range of amounts. These matters have been assigned to an EPA attorney and an enforcement investigator in Dallas. Nexen's meeting with the EPA, which was planned for late September 2005, was postponed because of the governments' increased workload caused by Hurricanes Katrina and Rita.

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of Nexen's security holders during the fourth quarter of 2005.

PART II

Item 5. Market for the Registrant's Common Shares and Related Stockholder Matters

Nexen's common shares are traded on the Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE) under the symbol NXY. On April 27, 2005, our shareholders approved a split of our issued and outstanding common shares on a two-for-one basis. All share and per-share amounts have been restated to reflect this split.

On April 27, 2005, our shareholders approved a 2-for-1 split of our common shares.

On December 31, 2005, there were 1,294 registered holders of common shares and 261,140,571 common shares outstanding. The number of registered holders of common shares is calculated excluding individual participants in securities positions listings. During the year, we made no purchases of our own equity securities.

Trading Range of Nexen's Common Shares

	TSX (Cdn $)		NYSE (US $)	
($/share)	High	Low	High	Low
2005				
First Quarter	35.50	23.55	29.18	19.44
Second Quarter	39.85	29.53	32.32	23.28
Third Quarter	60.67	40.25	51.73	31.95
Fourth Quarter	59.54	43.77	51.69	36.80
2004				
First Quarter	26.68	22.50	20.31	17.05
Second Quarter	28.25	23.40	21.15	17.25
Third Quarter	26.85	22.17	21.07	16.94
Fourth Quarter	29.33	24.09	23.28	19.60

In 2005, Nexen's common shares traded on the TSX from a low of $23.55 in Q1 to a high of $60.67 in Q3.

Quarterly Dividends Declared on Common Shares

($/share)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2005	0.05	0.05	0.05	0.05
2004	0.05	0.05	0.05	0.05

Payment date for dividends was the first day of the next quarter.

The Income Tax Act of Canada requires us to deduct a withholding tax from all dividends remitted to non-residents. According to the Canada-US Tax Treaty, we have deducted a withholding tax of 15% on dividends paid to residents of the United States, except in the case of a company that owns at least 10% of the voting stock, where the withholding tax is 5%.

The Investment Canada Act requires that a "non-Canadian", as defined, file notice with Investment Canada and obtain government approval prior to acquiring control of a Canadian business, as defined. Otherwise, there are no limitations, either under the laws of Canada or in Nexen's charter on the right of a non-Canadian to hold or vote Nexen's securities.

On February 3, 2000, at a Special Meeting of Shareholders, a Shareholder Rights Plan was approved. On May 2, 2002, at the Annual General and Special Meeting of Shareholders, an Amended and Restated Shareholder Rights Plan (Plan) was approved. According to the Plan, a right is attached to each present and future outstanding common share, entitling the holder to acquire additional common shares during the term of the right. Prior to the separation date, the rights are not separable from the

common shares, and no separate certificates are issued. The separation date would typically occur at the time of an unsolicited takeover bid, but our Board can defer the separation date.

Rights created under the Plan, which can only be exercised when a person acquires 20% or more of our common shares (a Flip-In Event), entitle each shareholder, other than the 20% buyer, to acquire additional common shares at one-half of the market price at the time of exercise. The Plan must be reapproved by shareholders on or before our annual general meeting in 2008 to remain effective past that date.

Item 6. **Selected Financial Data**

See page 119 for differences between Canadian & US GAAP.

Five-Year Summary of Selected Financial Data in Accordance with US GAAP

(Cdn$ millions)	2005	2004	2003	2002	2001
Results of Operations					
Net Sales					
Oil and Gas and Syncrude [1]	3,506	2,552	2,236	1,775	1,705
Other	426	392	396	367	373
Total Net Sales	3,932	2,944	2,632	2,142	2,078
Net Income from Continuing Operations	666	705	419	270	293
Basic Earnings per Common Share from Continuing Operations ($/share)	2.52	2.74	1.69	1.10	1.21
Diluted Earnings per Common Share from Continuing Operations ($/share)	2.47	2.71	1.68	1.09	1.20
Net Income	1,110	788	420	352	365
Basic Earnings per Common Share ($/share)	4.26	3.06	1.70	1.44	1.51
Diluted Earnings per Common Share ($/share)	4.17	3.03	1.68	1.42	1.50
Production Before Royalties (mboe/d) [2]	242	250	269	269	268
Production After Royalties (mboe/d) [2]	173	174	185	176	184
Financial Position					
Total Assets [2]	14,493	12,339	7,703	6,764	5,609
Long-Term Debt [3]	3,630	4,214	2,470	2,575	2,242
Shareholders' Equity	3,961	2,892	2,131	1,812	1,414
Capital Investment, including Acquisitions	2,638	4,264	1,432	1,545	1,325
Dividends per Common Share ($/share) [4]	0.20	0.20	0.163	0.15	0.15
Common Shares Outstanding (thousands)	261,141	258,399	251,212	245,932	242,404

Notes:

1 During 2003, we sold non-core conventional light oil assets in southeast Saskatchewan in Canada producing 9,000 bbls/d. In late 2004, we concluded production from our Buffalo field, offshore Australia, as anticipated. In the third quarter of 2005, we sold certain Canadian conventional oil and gas properties in Saskatchewan, British Columbia and Alberta producing 18,300 bbls/d. The results of these operations have been shown as discontinued operations.

2 In 2003, production increased from our deep-water Aspen development in the Gulf of Mexico in the United States. In 2004, production declined from our maturing assets in Yemen at Masila, in Canada and in the United States on the Gulf of Mexico Shelf. In late 2004, we acquired North Sea assets and began production from Block 51 in Yemen. In 2005, we sold producing properties in Canada and suffered hurricane-related downtime in the Gulf of Mexico. A full year's production from the North Sea and Block 51 in Yemen offset declines caused by these events.

3 In December 2004, we drew US$1.5 billion on unsecured acquisition credit facilities to finance the purchase of North Sea assets. The remainder of the purchase price was funded from cash on hand. The acquisition credit facility was repaid in 2005 with proceeds from the issuance of US $1.04 billion in senior notes in the first quarter and from our asset disposition program in the third quarter.

4 Quarterly dividends were increased to 5¢ per share in the fourth quarter of 2003.

We've done what we set out to do: delivered record results, met our production targets, reduced net debt, achieved exploration success and kept our major projects **on** time and **on** budget.

see the **value**

md&a

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following should be read in conjunction with the Consolidated Financial Statements included in this report. The Consolidated Financial Statements have been prepared in accordance with generally accepted accounting principles (GAAP) in Canada. The impact of significant differences between Canadian and United States (US) accounting principles on the financial statements is disclosed in Note 21 to the Consolidated Financial Statements. The date of this discussion is February 7, 2006.

Unless otherwise noted, tabular amounts are in millions of Canadian dollars. Our discussion and analysis of our oil and gas activities include our Syncrude activities since the product produced from Syncrude competes in the oil and gas market. Oil and gas volumes, reserves and related performance measures are presented on a working interest before-royalties basis. We measure our performance in this manner consistent with other Canadian oil and gas companies. Where appropriate, we have provided information on an after-royalty basis in tabular format.

Note: Canadian investors should read the Special Note to Canadian Investors on page 80 which highlights differences between our reserve estimates and related disclosures that are otherwise required by Canadian regulatory authorities.

EXECUTIVE SUMMARY OF 2005 RESULTS

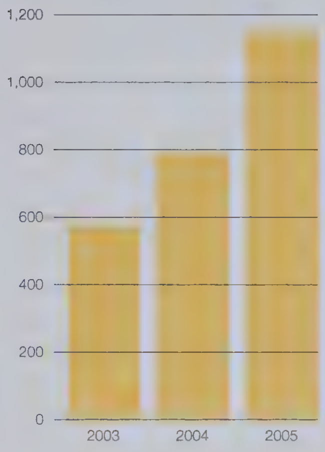
(Cdn$ millions)	2005	2004	2003
Net Income	1,152	793	578
Earnings per Common Share ($/share)	4.43	3.08	2.33
Cash Flow from Operating Activities	2,143	1,606	1,405
Production before Royalties (mboe/d) [1]	242	250	269
Production after Royalties (mboe/d)	173	174	185
Capital Investment, including Acquisitions	2,638	4,264	1,494
Net Debt [2]	3,641	4,219	1,690
Average Foreign Exchange Rate (Canadian to US dollar)	0.83	0.77	0.71

Notes:

1 Production before royalties reflects our working interest before royalties and includes production of synthetic crude oil from Syncrude. We have presented our working interest before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies.

2 Long-term debt less working capital.

Net Income
(Cdn$ millions)



We achieved record financial results in 2005 with net income exceeding $1 billion for the first time in company history. We exceeded our production targets, notwithstanding the sale of oil and gas properties in Canada and the impact of hurricanes in the US. We also successfully reduced our net debt while managing our largest capital program ever. We made significant progress on our strategic initiatives by moving closer to first production at Buzzard and Long Lake, beginning commercial CBM development at Corbett, Doris and Thunder and making a potentially significant discovery at Knotty Head in the US Gulf. In addition, we received record net revenues from our marketing group.

We achieved record financial results due to all-time high commodity prices, gains on dispositions and a record contribution from marketing.

Record high commodity prices throughout the year underpinned our results. We also realized a gain of $225 million on disposition of Canadian conventional oil and gas properties, and a gain of $193 million on the initial public offering of a portion of our chemicals business through the Canexus Income Fund. We raised more than $1.4 billion from these transactions and used the proceeds to reduce net debt and fund our capital programs.

Our major capital projects remain on time and on budget. Buzzard is approximately 88% complete and we are on track for first production in late 2006. Peak production is expected to be approximately 200,000 boe/d (85,000 boe/d net to us), royalty free. At our Long Lake project, we are on track to complete and tie-in our commercial SAGD wells and begin steam injection late in 2006. Production is expected to ramp up before the upgrader is complete in the second half of 2007. We expect our share of synthetic crude oil from Long Lake to be 30,000 bbls/d. We are already planning to duplicate Long Lake in a phased manner, and expect to increase our synthetic crude oil production to 120,000 bbls/d over the next ten years. At Syncrude, the Stage 3 expansion is almost complete and we expect our share of production capacity there to increase by 8,000 bbls/d in 2006.

Our capital program is also delivering results that will add to our future growth. In the Gulf of Mexico, we made a discovery at Knotty Head, our first sub-salt discovery and the deepest well ever drilled in the Gulf. We are presently drilling a sidetrack well to determine the extent of our discovery. Offshore Nigeria, we had further drilling success at Usan on Block OPL-222 and expect to book proved reserves once the project is sanctioned. In Canada, we are moving forward with commercial development of our coal bed methane resources and are looking to increase recovery rates from our heavy oil properties through the innovative use of technology.

Our major capital projects remain on time and on budget and our capital program is delivering results that will add to our future growth.

New production from Block 51 in Yemen and Scott and Telford in the UK North Sea offset natural declines on our base producing assets in Canada, the Gulf of Mexico and at Masila in Yemen. We sold more than 18,000 boe/d of Canadian conventional production and lost approximately 6,000 boe/d of Gulf of Mexico production as a result of hurricanes. While damage to most of our facilities was fairly minor, post-hurricane start-up delays caused by damage to surrounding infrastructure required some of our production to be shut-in for an extended period. Most of our fields in the Gulf are now up and running at full production.

In 2005, our stock price increased 128%, increasing shareholder value by over $8 billion.

We added 82 mmboe of proved oil and gas and Syncrude reserves before royalties, almost fully replacing our 2005 production of 90 mmboe.

In 2005, our stock price increased from $24.35 to $55.42 per share, increasing shareholder value by more than $8 billion. It also increased our expense for employee stock-based compensation programs, and we expensed $490 million during the year. In 2005, Nexen was the 7th best performing stock among companies on the S&P TSX Composite Index.

Following our 2004 North Sea acquisition, we purchased WTI put options to provide an annual average floor price of US$43/bbl and US$38/bbl on 60,000 bbls/d of production in 2005 and 2006, respectively. At the end of 2004, these put options had a market value of $200 million. As a result of continued strong crude oil prices, the value of these options was only $4 million at the end of 2005. We expensed the $196 million decrease in value in 2005.

Throughout 2005, the Canadian dollar strengthened relative to the US dollar. Our sales revenue is denominated in or referenced to US dollars. As a result, our revenues decline as the US dollar weakens. On the other hand, our US-dollar capital spending, operating costs and US-dollar denominated debt are lower when translated to Canadian dollars. Overall, the weaker US dollar reduced our 2005 cash flow from operating activities and net income by $251 million and $116 million, respectively, and debt decreased by $109 million.

We added 82 mmboe of proved oil and gas and Syncrude reserves before royalties, replacing the majority of our 2005 production of 90 mmboe. Our major development activities, principally at Buzzard and Syncrude, contributed 45 mmboe of the additions. Reserves were also added from ongoing exploitation in Yemen, Canada, the Gulf of Mexico and the North Sea. Once again, SEC regulations that require us to recognize bitumen reserves using year-end prices, did not allow us to book any proved bitumen reserves for Long Lake because of high natural gas costs and wide light/heavy differentials. Under Canadian regulations, we would recognize 200 mmbbls of high-value proved synthetic reserves. We also sold 49 mmboe of proved reserves in Canada during the year.

In 2006, we are planning our largest capital program ever. We expect to invest $2.9 billion to develop core assets and develop and explore for new growth opportunities. Almost half of this capital will be directed toward major development projects at Buzzard, Long Lake and Syncrude, as well as the development of coal bed methane from the Upper Mannville coals in the Fort Assiniboine area of Alberta. On the exploration front, we will continue to appraise our Knotty Head discovery and expect to drill 20 high-impact wells primarily in the Gulf of Mexico, North Sea, offshore West Africa and Yemen.

We expect our 2006 production to average between 220,000 boe/d and 240,000 boe/d, before royalties, and between 165,000 boe/d and 180,000 boe/d after royalties. In 2007, we expect our before-royalties production to grow to between 300,000 boe/d and 350,000 boe/d. Most of our new production is subject to little or no royalties and generates significantly higher margins than our current production.

CAPITAL INVESTMENT

(Cdn$ millions)	Estimated 2006	2005	2004
Major Development	1,300	1,550	663
Early Stage Development	300	54	19
New Growth Exploration	600	456	266
Core Asset Development	600	504	634
	2,800	2,564	1,582
Acquisitions	–	20	2,587
Total Oil & Gas and Syncrude	2,800	2,584	4,169
Marketing, Corporate, Chemicals and Other	100	54	95
Total Capital	**2,900**	**2,638**	**4,264**

Our strategy and capital programs are focused on growing long-term value for shareholders. To maximize value, we invest in:

- core assets for short-term production and free cash flow to fund capital programs and repay debt;
- development projects that convert our discoveries into new production and cash flow; and
- exploration projects for longer-term growth.

As conventional basins in North America mature, we have been transitioning our operations toward less mature basins and unconventional resources. Our key focus areas include the North Sea, Athabasca oil sands, Canadian coal bed methane, Gulf of Mexico, offshore West Africa and the Middle East—areas we believe have attractive fiscal terms and significant remaining opportunity, and where we have some competitive advantage.

In 2005, we invested more than $2.6 billion in capital expenditures, mostly in multi-year development projects and long cycle-time exploration. In 2006, we are managing our largest development and exploration program ever. We plan to invest more than $2.9 billion in our oil and gas and Syncrude assets. About 45% of this is focused on multi-year development projects, 24% on core assets to sustain production and provide cash flow, and 21% on drilling high-impact exploration wells and building our acreage position. The rest will be spent on early stage development activities.

In 2005, most of our capital was invested in multi-year development projects and long cycle-time exploration.

2005 Investment Program

(Cdn$ millions)	Major Development	Early Stage Development	New Growth Exploration	Core Asset Development	Total
Oil and Gas					
Synthetic (mainly Long Lake)	743	31	16	–	790
North Sea	469	10	59	87	625
Yemen	161	–	41	75	277
United States	4	–	211	144	359
Canada	33	10	74	130	247
Other Countries	–	3	55	11	69
Syncrude	140	–	–	57	197
	1,550	**54**	**456**	**504**	**2,564**
Chemicals	–	–	–	14	14
Marketing, Corporate and Other	–	–	–	40	40
Total Capital	**1,550**	**54**	**456**	**558**	**2,618**
As a % of Total Capital	59%	2%	17%	22%	100%

2006 Estimated Capital

(Cdn$ millions)	Major Development	Early Stage Development	New Growth Exploration	Core Asset Development	Total
Oil and Gas					
Synthetic (mainly Long Lake)	650	100	–	10	760
North Sea	450	100	75	85	710
Yemen	–	–	35	160	195
United States	–	20	255	235	510
Canada	150	60	120	80	410
Other Countries	–	20	115	–	135
Syncrude	50	–	–	30	80
	1,300	**300**	**600**	**600**	**2,800**
Marketing, Corporate and Other	–	–	–	100	100
Total Capital	**1,300**	**300**	**600**	**700**	**2,900**
As a % of Total Capital	45%	10%	21%	24%	100%

2006 Estimated Capital

Major Development (45%)
Early Stage Development (10%)
New Growth Exploration (21%)
Core Asset Development (24%)

Major and Early Stage Development Projects

More than 60% of our 2005 capital investment was directed toward early stage and major development projects including Buzzard, Long Lake, Syncrude Stage 3, Yemen Block 51 and CBM. These projects are characterized by multi-year investments that result in timing differences between reserve additions and capital expenditures, but each project has attractive full-cycle finding and development costs. Our new growth development resulted in proved reserve additions of 45 mmboe.

Our Long Lake and Buzzard developments are on time and on budget.

Synthetic

We invested $774 million to develop our insitu oil sands resource in 2005, $743 million of this at Long Lake. The base Long Lake project remains on schedule and on budget. Detailed project engineering is substantially complete, and approximately 69% of the project's total costs have been committed. Steam injection is expected to begin in late 2006, followed by a ramp-up in bitumen production. The upgrader is scheduled to start operations in the second half of 2007.

To enhance reliability, ensuring bitumen feedstock supply and building capacity for future growth, we are expanding our steam generating facilities so we can operate at a steam-oil ratio of up to 3.3 compared with the existing design of 2.5. This expansion is expected to cost up to $250 million ($125 million, net to us). In optimizing the value from the project, we will also construct a facility to concentrate soot produced by the gasifier and thereby reduce disposal costs. This facility is expected to cost approximately $110 million ($55 million, net to us). These two projects will increase our total capital investment to construct Long Lake by 10% to $1.9 billion.

At peak rates of premium synthetic crude, Long Lake Phase 1 should provide us with cash flow of between $400 million and $500 million per year, assuming oil prices of US$50/bbl (WTI). We are planning to increase synthetic crude oil production to 240,000 bbls/d over the next 10 years (120,000 bbls/d, net to us) in phases of 60,000 bbls/d (30,000 bbls/d, net to us) using the same technology as Long Lake. Phase 2 bitumen production is expected to begin in late 2010, with upgrader commissioning in 2011. In 2005, we invested $31 million to further evaluate our existing resource and acquire additional resource. We have made commitments for some of the long-lead time modules for phase 2. In 2006, we expect to invest $650 million on the ongoing development of Long Lake and $100 million in additional drilling and seismic to develop our oil sands leases and advance our regulatory applications.

North Sea—Buzzard

At Buzzard, we invested $439 million in 2005. Buzzard is progressing on schedule and on budget. Development of the facilities is approximately 88% complete. We are currently drilling the production wells and expect to install the utilities and production decks during the second quarter of 2006. First oil is expected in late 2006. At its peak, Buzzard is expected to add approximately 85,000 boe/d of net production and between $1.6 billion and $1.7 billion of annual pre-tax cash flow, assuming US$50/bbl (WTI). In 2006, we expect to spend $450 million on Buzzard and $100 million to complete appraisal and development evaluation work on a number of small discoveries in the North Sea.

Yemen

In Yemen on Block 51, we began production in late 2004 using an early production system. In 2005, we invested $161 million to construct permanent production facilities and further develop the fields. The permanent facilities are expected to be fully commissioned in early 2006.

We are developing the first commercial CBM project in Mannville coals.

Canada—Coal Bed Methane

In Canada, we are developing the first commercial CBM project in Mannville coals. In 2005, we invested $33 million in CBM development, and in 2006, we plan to spend $150 million to develop 115 gross (53 net) sections using single-leg and multiple-leg wells, and construct gas gathering and processing facilities. We expect our CBM production to be modest in 2006, with growth in 2007 and beyond as we dewater the reservoirs and expand our developments. We are targeting to add 150 mmcf/d of production by 2011 from our CBM projects. We have more than 600 net sections of CBM lands.

Syncrude—Stage 3 Expansion

We invested $140 million in 2005 for the Syncrude Stage 3 expansion. This project was approximately 98% complete at year end, with 65% of the new units completed and operating reliably throughout 2005. Commissioning of all remaining Stage 3 units is underway. The expansion is expected to be completed and fully on stream by mid year, adding approximately 8,000 bbls/d of production capacity, net to us. We expect to spend $50 million in 2006 to complete and commission the Stage 3 upgrader expansion.

New Growth Exploration

We invested $456 million in exploration in 2005. Approximately $140 million of this was invested in land, seismic and other early stage exploration activities. The balance was invested to drill 20 high-impact exploration wells. This resulted in a number of exploration successes, including the potentially significant Knotty Head discovery in the Gulf of Mexico where we have a 25% interest. We also had smaller discoveries in the Gulf at Big Bend, Anduin and Wrigley. In total, we participated in approximately one-third of deep-water discoveries in the Gulf of Mexico in 2005. Offshore West Africa, we drilled two successful appraisal wells at Usan on Nigeria's OPL-222. Despite our exploration success, we only recognized 4 mmboe of proved reserves because of additional appraisal work required to make a decision on commercial development.

We had exploration success in 2005, including a potentially significant discovery at Knotty Head.

Knotty Head is a potentially significant discovery on Green Canyon Block 512. A sidetrack appraisal well commenced drilling in late 2005 and is nearing completion. Additional appraisal drilling is planned within the next year to determine the extent of the discovery.

We are proceeding with development of the Wrigley discovery on Mississippi Canyon 506. We plan to sub-sea tieback the well to nearby infrastructure, with first production expected in the second half of 2006. We plan to complete our Big Bend discovery and tie back to existing infrastructure in 2007. At our Anduin discovery, we plan to drill an appraisal well in 2006 to determine the resource size and development options.

Internationally, we drilled three small discoveries in the North Sea at Polecat, Yeoman and Black Horse. Their ultimate development is being evaluated and may depend on additional exploration success in the area. We have a 40% interest in Polecat, a 50% interest in Yeoman and a 60% interest in Black Horse, and we operate all three wells.

On Nigeria OPL-222, offshore West Africa, the Usan-7 and Usan-8 appraisal wells were successfully drilled during 2005. Appraisal of the Usan field is now complete and a preliminary field development plan has been submitted to Nigerian governmental agencies for approval. Preparation for basic engineering and tendering of contracts is proceeding on a multi-well development plan. The current design consists of a purpose-built floating production, storage and offshore loading facility (FPSO) capable of handling peak production rates of 160,000 bbls/d with storage capacity of 2 million barrels. Following government approvals of the final field development plan, the partners expect to formally sanction the project in late 2006. In 2005, we completed drilling the deep-water Efere well. This well was unsuccessful and its capital costs have been expensed. During 2006, the exploration and appraisal program outside the Usan field will continue on the block.

In 2006, we expect to invest $600 million in exploration capital to drill 20 high-impact wells primarily in the Gulf of Mexico, the North Sea, offshore West Africa and Yemen. We currently have drilling rigs secured for the majority of our 2006 program. We have an extensive inventory of exploration prospects in the Gulf of Mexico. To ensure the continuity of our deep-water drilling program, we have contracted a new-build fifth-generation dynamically-positioned semi-submersible drilling rig, which is scheduled to be completed in 2009. The contract provides us access to the rig for two years over a three-and-a-half-year period.

In 2006, we plan to drill 20 high-impact exploration wells.

Core Asset Development

In 2005, we invested $504 million in core asset development and minor property acquisitions that added 33 mmboe of proved reserves. Our strategy is to maximize the value we extract from our core assets, in addition to adding reserves and production. In 2006, we plan to invest $600 million in our core assets including gas opportunities in the Eugene Island and Vermillion areas in the shallow-water Gulf of Mexico shelf, development activities at Scott and Telford in the North Sea and development of our BAK-A and BAK-B fields in Block 51, Yemen.

FINANCIAL RESULTS

Year-to-Year Change in Net Income

For more info, see:	(Cdn$ millions)	2005 vs 2004	2004 vs 2003
	Net Income for 2004 and 2003 [1]	**793**	**578**
	Favourable (unfavourable) variances:		
	Cash Items		
page 37	Production Volumes, After Royalties		
	Crude Oil	39	(116)
	Natural Gas	(55)	(8)
	Change in Crude Oil Inventory	4	40
	Total Volume Variance	(12)	(84)
page 40	Realized Commodity Prices		
	Crude Oil	648	365
	Natural Gas	165	–
	Total Price Variance	813	365
page 43	Oil and Gas Operating Expense		
	Conventional	(64)	(55)
	Synthetic	(27)	(2)
	Total Operating Expense Variance	(91)	(57)
page 49	Marketing Contribution	49	(14)
page 52	Chemicals Contribution	31	10
page 53	General and Administrative	(96)	(30)
	General and Administrative—Stock-Based Compensation Paid	(60)	(9)
page 53	Interest Expense	46	26
page 54	Current Income Taxes	(91)	(38)
page 55	Other	(69)	(22)
	Total Cash Variance	520	147
	Non-Cash Items		
page 45	Depreciation, Depletion, Amortization and Impairment		
	Oil & Gas and Syncrude	(308)	271
	Other	(19)	13
page 46	Exploration Expense	(5)	(45)
page 53	General and Administrative—Stock-Based Compensation Accrual	(337)	(70)
page 54	Future Income Taxes	348	(176)
page 55	Increase (Decrease) in Fair Value of Crude Oil Put Options	(252)	56
page 55	Gains from Divestiture Programs	418	–
page 55	Other	(6)	19
	Total Non-Cash Variance	(161)	68
	Net Income for 2005 and 2004 [1]	**1,152**	**793**

Note:

1 Includes results of discontinued operations (see Note 14 to our Consolidated Financial Statements). Significant variances in net income are explained in the sections that follow. The impact of foreign exchange on our operations is summarized on page 55.

Production

	2005		2004		2003	
	Before Royalties [1]	After Royalties	Before Royalties [1]	After Royalties	Before Royalties [1]	After Royalties
Oil and Liquids (mbbls/d)						
Yemen	112.7	60.6	107.3	53.5	116.8	57.5
Canada [2]	29.2	22.6	36.2	28.2	46.3	35.4
United States	22.2	19.6	30.0	26.5	28.3	25.0
United Kingdom	12.6	12.6	1.5	1.5	–	–
Australia [3]	–	–	2.7	2.5	6.1	5.6
Other Countries	5.6	5.1	5.3	4.7	5.4	4.6
Syncrude (mbbls/d) [4]	15.5	15.3	17.2	16.6	15.3	15.2
	197.8	135.8	200.2	133.5	218.2	143.3
Natural Gas (mmcf/d)						
Canada [2]	124	101	146	115	158	125
United States	116	99	148	126	145	122
United Kingdom	23	23	3	3	–	–
	263	223	297	244	303	247
Total (mboe/d)	**242**	**173**	**250**	**174**	**269**	**185**

Notes:

1 We have presented production volumes before royalties as we measure our performance on this basis consistent with other Canadian oil and gas companies.

2 Includes the following production from discontinued operations. See Note 14 to our Consolidated Financial Statements.

	2005	2004	2003
Before Royalties			
Oil and Liquids (mbbls/d)	6.7	11.7	19.6
Natural Gas (mmcf/d)	24	47	50
After Royalties			
Oil and Liquids (mbbls/d)	5.3	9.0	14.5
Natural Gas (mmcf/d)	17	33	34

3 Comprises production from discontinued operations. See Note 14 to our Consolidated Financial Statements.

4 Considered a mining operation for US reporting purposes.

2005 vs 2004—Lower production decreased net income by $12 million

Production before royalties declined 3% during the year, while production after royalties remained consistent with 2004 levels. New royalty-free production from the UK North Sea partially offset the sale of higher-royalty production from Canada. We sold Canadian production during the year to reduce debt used to fund our acquisition of offshore oil and gas assets in the North Sea. Production was lower as a result of hurricane activity in the Gulf of Mexico in the second half of the year. Removing the impact of the Canadian asset sales and the lost volumes attributable to Hurricanes Katrina and Rita, our 2005 production before royalties would have increased 3% from 2004.

Even after Canadian dispositions and hurricanes in the Gulf of Mexico, 2005 production before royalties declined only 3%.

The following table summarizes our production changes year over year:

(mboe/d)	Before Royalties	After Royalties
2004 Production	250	174
Canada—Disposition of Properties	(9)	(6)
Gulf of Mexico—Hurricane Related Downtime	(6)	(5)
	235	163
Production changes		
Block 51 in Yemen	25	16
North Sea	14	14
Masila Block in Yemen	(18)	(8)
Gulf of Mexico	(7)	(6)
Canada	(2)	(2)
Australia	(3)	(3)
Syncrude	(2)	(1)
2005 Production	**242**	**173**

See page 56 for production expected in 2006.

Future production increases are expected to come from Syncrude in 2006 and our North Sea Buzzard project in late 2006, along with Long Lake synthetic production in 2007. Production volumes discussed in this section represent our working interest before royalties.

Yemen

Yemen production increased 5% from 2004 as we replaced maturing production from Masila with new production from Block 51. Masila production declined 18%. As the field nears the end of its contract term, we are strategically managing development capital to optimize recovery of remaining reserves. In 2005, we drilled 36 development wells compared with 73 wells in 2004. While new wells coming on stream are yielding strong production rates, we expect Masila to continue declining in the future.

On Block 51, production from the East Al Hajr field averaged 25,600 bbls/d during the year. We have been operating from temporary facilities and expect to complete the permanent central processing facility in the first quarter of 2006. During the year, we drilled 20 development wells. We expect our share of total production from Yemen to average between 90,000 bbls/d and 100,000 bbls/d in 2006.

Canada

In 2005, we sold Canadian conventional oil and gas properties producing 18,300 boe/d.

In the third quarter, we sold conventional oil and gas properties in Alberta, British Columbia and Saskatchewan that were producing 18,300 boe/d. Production from our remaining natural gas and heavy oil properties declined marginally. In 2006, we are focusing our capital on drilling infill shallow gas wells, developing our coal bed methane projects and developing new technologies to increase heavy oil recovery. In 2006, we plan to drill more than 300 net wells on our properties and expect our Canadian production to average between 35,000 boe/d and 40,000 boe/d.

Gulf of Mexico

In the Gulf of Mexico, hurricanes reduced our annual volumes by about 6,000 boe/d.

Gulf of Mexico production declined 24%, or about 13,000 boe/d from 2004. The effects of Hurricanes Katrina and Rita reduced volumes by approximately 6,000 boe/d as a result of shut-in production and subsequent start-up delays following damage to our facilities and third-party infrastructure. We carry insurance which, subject to certain deductibles, we expect will cover property damage and business interruption up to defined limits. We expensed insurance-related costs of US$34 million as a result of the hurricanes.

In the deep water, natural declines and increasing water-cuts at Aspen reduced volumes by 8,000 boe/d from 2004. We plan to drill another development well at Aspen in 2006 to tap potential unrecovered reserves. Strong production from development drilling on the shelf and an additional deep-water well at Gunnison partly offset the Aspen decline. A second development well was drilled at Gunnison and came on stream in January 2006. We plan to continue development drilling on our maturing shelf properties to maintain current production rates and tie-in our deep-water discoveries at Wrigley and Dawson Deep. We expect our Gulf production to average between 40,000 boe/d and 45,000 boe/d in 2006.

North Sea

The Scott and Telford fields acquired in December 2004 contributed a full year of production averaging 16,400 boe/d. Our North Sea production was impacted by two generator failures on the Scott platform in early May. We completed repair work and performed a major maintenance turnaround on the platform in the third quarter. The platform upgrades and infill drilling enabled us to increase production rates in the second half of the year.

Our non-operated Farragon field came on stream in November and was producing 3,900 boe/d net to Nexen from two producing wells at year end. We expect Farragon to contribute between 3,000 boe/d and 4,000 boe/d to our production in 2006.

Our Buzzard development project is on time and on budget, and we expect to begin producing from this field in late 2006. We expect our total year production from our North Sea assets, which were producing approximately 19,000 boe/d when we purchased them in late 2004, to average between 25,000 boe/d and 30,000 boe/d in 2006.

We expect our North Sea production to average between 25,000 and 30,000 boe/d in 2006.

Other Countries

In 2005, we completed abandonment activities in Australia, which ceased production in late 2004. Production from the Guando field in Colombia was consistent with 2004, as we maintained rates with nine additional development wells. We expect to maintain production rates in Colombia in 2006.

Syncrude

Syncrude production decreased 10% from 2004 as a result of maintenance and turnaround work on various units during 2005. In January, the delayed start-up of the LC finer and unscheduled repairs to a hydrogen plant limited the hydrotreating capacity for the first quarter. Production was reduced again later in the year for a scheduled 52-day turnaround of the vacuum distillation unit. We exited 2005 at 20,000 bbls/d (net to us) following completion of the turnarounds. Start-up of the Stage 3 expansion is expected to increase our production capacity by approximately 8,000 bbls/d in mid-2006, and we expect our share of total-year production from Syncrude to average between 20,000 bbls/d and 22,000 bbls/d.

The Syncrude Stage 3 expansion is expected to increase our volumes to between 20,000 and 22,000 bbls/d in 2006.

2004 vs 2003—Lower production decreased net income by $84 million

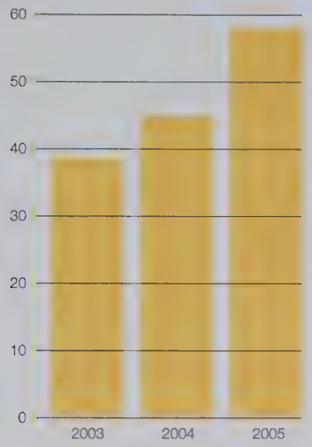
Production after royalties decreased 6% from 2003, half of which was attributable to the sale of our non-core Canadian light oil properties in southeast Saskatchewan in August 2003.

Production before royalties decreased 7%, caused by the sale of properties in August 2003 and declining base production from our maturing conventional assets in the shallow-water Gulf of Mexico, Masila in Yemen and our remaining Canadian properties. Delays in development drilling programs also contributed to reduced volumes in Yemen and in the shallow-water Gulf of Mexico. However, our deep-water Gulf of Mexico assets performed strongly, achieving record production at Aspen and Gunnison. This partially offset the declining volumes from our maturing conventional properties.

In the fourth quarter of 2004, new volumes from our North Sea acquisition and initial production from Block 51 in Yemen offset reduced volumes from Australia, where we produced our final barrel in November 2004.

Syncrude production increased 12% from 2003, achieving a new annual record despite maintenance shut-down of the LC finer at year end.

Average Realized Oil and Gas Price
(Cdn$/boe)



Commodity Prices

	2005	2004	2003
Crude Oil			
West Texas Intermediate (US$/bbl)	56.58	41.40	31.04
Differentials [1] (US$/bbl)			
Heavy Oil—LLK	20.82	13.53	8.63
MARS	6.59	6.15	3.53
Masila	5.71	4.84	3.03
Dated Brent	2.20	–	–
Producing Assets (Cdn$/bbl)			
Yemen	62.07	47.59	39.45
Canada	40.51	36.60	32.37
United States	57.63	46.60	37.68
United Kingdom	60.55	46.81	–
Australia	–	51.22	43.14
Other Countries	59.96	43.07	38.22
Syncrude	71.00	52.80	43.36
Corporate Average (Cdn$/bbl)	58.98	45.90	38.04
Natural Gas			
New York Mercantile Exchange (US$/mmbtu)	8.99	6.19	5.60
AECO (Cdn$/mcf)	8.04	6.44	6.35
Producing Assets (Cdn$/mcf)			
Canada	7.51	5.76	5.64
United States	10.56	7.89	8.16
United Kingdom	7.86	8.28	–
Corporate Average (Cdn$/mcf)	8.89	6.85	6.85
Nexen's Average Realized Oil and Gas Price (Cdn$/boe)	**57.97**	**44.94**	**38.63**
Average Foreign Exchange Rate Canadian to US Dollar	0.8253	0.7683	0.7135

Note:
1 These differentials are a discount to WTI.

2005 vs 2004—Higher realized prices added $813 million to net income

WTI reached record highs in 2005 averaging US$56.58/bbl, an increase of 37% compared with US$41.40/bbl in 2004. We realized record annual prices for our crude oil, averaging $58.98/bbl in 2005, an increase of 28% over 2004. Although crude oil reference prices increased 37% over 2004, our realized prices only increased by 28%, because of wider crude oil differentials and a weaker US dollar.

Our realized gas price increased 30% from a year ago to average $8.89/mcf. NYMEX increased 45% in the same period, averaging US$8.99/mmbtu.

The full benefit of higher benchmark prices wasn't reflected in our realized prices because of the weaker US dollar in 2005. All of our oil sales and most of our gas sales are denominated in, or referenced to, US dollars. As a result, the weaker US dollar decreased net sales for the year by approximately $270 million, and reduced our realized crude oil and natural gas prices by approximately $4.40/bbl and $0.65/mcf, respectively, compared with 2004.

A stronger Canadian dollar reduced our realized oil and gas prices and reduced net sales by approximately $270 million.

Crude Oil Reference Prices

Crude oil prices remained strong in 2005 reaching new highs and new levels of volatility. WTI prices peaked on August 31 when trading broke through US$70/bbl. The trading range for WTI in 2005 was between US$41.25 and US$70.85. While global demand was moderate and supply levels adequate, the stability and security of long-term supply remained a concern, along with tightening refining capacity worldwide. Throughout the year, events that threatened supply or strained refining capacity caused prices to spike.

2005 WTI Monthly Average Oil Price
(US$/bbl)

Several factors contributed to increased prices and greater market volatility throughout the year:

- hurricane activity in the US Gulf of Mexico removed approximately 110 million barrels of supply and temporarily shut down refining capacity;
- growing participation by hedge funds and banks in the commodity markets;
- ongoing labour and political unrest in crude oil producing regions, particularly the Middle East, West Africa and Venezuela;
- political disputes or disagreements between producing and consuming regions; and
- the weaker US dollar.

With sufficient levels of supply and moderate demand, crude oil inventories, particularly in North America, are at the top of their historical range and almost 30 million barrels higher than last year. Given the shortage in refining capacity, product inventories, unlike crude oil inventories, have remained tight throughout most of the year.

Most worldwide refining capacity requires light-sweet crude oil as feedstock, but only a small portion of new supply is light or sweet. With light-sweet crudes in greatest demand but limited supply, prices for both WTI and Brent have risen. Events that threatened this supply or refining capacity created volatility.

Crude Oil Differentials

Crude oil differentials widened in 2005 because of a strong WTI and greater demand worldwide for light-sweet crude oil than for heavy sour crude. World supply of heavy oil has been increasing faster than the supply of light crude, and refining constraints and environmental standards continue to tighten in favour of lighter crudes. Therefore, we expect differentials between light and heavy oil to remain wide.

In Canada, heavy crude oil had some short-lived strength during the summer, but generally differentials widened in 2005, with benchmark LLK differentials averaging US$20.82. Differentials narrowed in the summer, as demand for heavy blends increased relative to light blends, reflecting normal summer demand for asphalt. Hurricane activity kept differentials narrow for longer than normal, as much of the heavy oil production from the Gulf to the US mid-continent was shut-in, increasing the demand for Canadian heavy oil. The heavy differential has since widened again, and we expect it to remain wide into 2007, when additional conversion capacity will enable more heavy oil.

Our US Gulf Coast MARS differential widened slightly in relation to 2004, averaging US$6.59/bbl in 2005. While the differential strengthened during the year because of growing demand from US-based refiners, it did not outpace WTI, resulting in a slightly wider differential. With refineries damaged by hurricanes, there was a temporary decline in demand that caused the MARS differential to widen to US$15. Late in the year, the differential narrowed to normal levels with the recovery of demand from refiners.

The Masila differential widened relative to WTI during 2005, averaging US$5.71/bbl compared with US$4.84/bbl in 2004. Despite an increase in demand from Asia and North America for sweeter blends, the differential still widened as a result of strong WTI pricing throughout 2005.

The Brent/WTI differential strengthened during 2005, averaging US$2.20/bbl, resulting in a solid crude oil price for our North Sea production. Strong demand from European refiners, an increase in Asian demand and lost production in the North Sea combined to push Brent up relative to the North American WTI benchmark.

NYMEX reached record highs and experienced increased volatility.

Natural Gas Reference Prices

Natural gas prices averaged US$8.99/mmbtu, reaching record highs and experienced increased volatility. Prices early in the year were propped up by strong oil prices. The disruptions caused by the hurricanes pushed North American gas prices to new highs. The volatility did not end with the hurricane activity, but continued into the winter, as markets speculated on the impact of a cold or mild winter on tight supply. Prices peaked on December 13, with NYMEX gas settling at US$15.38/mmbtu. Prices have since softened, mainly from a weak winter heating season and low inventory withdrawals.

2005 NYMEX Monthly Average Natural Gas Prices
(US$/mmbtu)

2004 vs 2003—Higher realized prices added $365 million to net income

Crude oil prices reached record levels in 2004, supported by supply concerns, high demand and speculative traders increasing volatility to all-time highs. The positive impact of strong crude oil reference prices was offset in part by the weakening US dollar and widening crude oil quality differentials.

All of our oil sales and most of our gas sales are denominated in, or referenced to, US dollars. As a result, a stronger Canadian dollar relative to the US dollar reduced our realized crude oil price by $3.50/bbl and our realized natural gas price by $0.50/mcf. In total, our net sales decreased $220 million from 2003 because of the weakening US dollar. The Canadian to US dollar exchange rate closed the year at 83¢.

Operating Costs

(Cdn$/boe)	2005 Before Royalties [1]	2005 After Royalties	2004 Before Royalties [1]	2004 After Royalties	2003 Before Royalties [1]	2003 After Royalties
Conventional Oil and Gas						
Yemen	3.63	6.75	2.80	5.64	2.16	4.37
Canada	8.21	10.34	7.12	8.98	6.00	7.76
United States	6.35	7.33	5.30	6.12	4.49	5.19
United Kingdom	14.90	14.90	8.26	8.26	–	–
Australia	–	–	32.94	35.73	18.60	20.21
Other Countries	5.55	6.08	3.76	4.09	7.47	9.01
Average Conventional	6.03	8.70	5.13	7.59	4.17	6.24
Synthetic Crude Oil						
Syncrude	26.95	27.22	19.89	20.61	21.96	22.18
Average Oil and Gas	**7.36**	**10.34**	**6.15**	**8.83**	**5.19**	**7.56**

Note:

1 Operating costs per boe are our total oil and gas operating costs divided by our working interest production before royalties. We use production before royalties to monitor our performance consistent with other Canadian oil and gas companies.

2005 vs 2004 – Higher oil and gas operating costs decreased net income by $91 million

Higher operating costs reflect the change in our profile as more of our production is coming from higher-cost areas such as the North Sea and from Canadian heavy oil following the Canadian property sales completed during the year. Operating costs were negatively impacted by storm-related costs and maintenance activities. In addition, high levels of industry activity and higher energy costs, driven by record commodity prices, have increased our operating costs.

Higher operating costs per boe reflect a change in our production profile, storm-related costs, maintenance activities, higher energy prices and industry cost pressures.

Our operations at Masila in Yemen are maturing and have higher operating costs, mainly from increased service rig activity to minimize production declines. These higher costs added 9¢/boe to our corporate average. Costs on a per-unit basis will continue to rise with increasing workover and water handling efforts and from declining production. Block 51 operating costs were higher than Masila, reflecting the use of temporary production facilities. Higher operating costs from Block 51 increased our corporate average by 53¢/boe. We expect operating costs at Block 51 to decrease in 2006 when we complete the permanent central processing facility early in the year.

Industry cost pressures and the sale of conventional production increased our Canadian unit operating costs in 2005. Although we sold high-cost production relative to our corporate average, we expect our overall Canadian operating costs to increase as we will have proportionately higher production from our heavy oil properties. These properties have higher operating costs and lower recovery rates compared to the lighter oil production that was sold. We are focused on increasing recovery rates from our heavy oil properties by developing new technologies.

In the Gulf of Mexico, lower volumes of higher-cost barrels at Aspen, along with $12 million of Aspen-1 intervention costs expensed in 2004, decreased our corporate average by 10¢/boe. Workovers on our shelf properties, coupled with lower production and property damage costs not covered by insurance, increased our corporate average by 5¢/boe from 2004.

The addition of higher-cost North Sea production increased our corporate average unit costs by $1.14/boe. Our North Sea operating costs were higher than anticipated as a result of maintenance and repair work caused by generator failures in the second quarter and major maintenance turnaround and facilities upgrading at the Scott platform in the third quarter. We expect our North Sea operating costs to decrease on a per-unit basis in 2006.

Our Australian operations ceased in late 2004 and the exclusion of these high-cost, late-life barrels reduced our corporate average by 57¢/boe.

We expect our 2006 operating costs per unit to increase due to a change in our production mix and industry cost pressures.

US-dollar denominated operating costs were lower when translated to Canadian dollars as a result of the weak US dollar. Our corporate average was reduced by 30¢/boe as a result.

Syncrude operating costs per boe were 35% higher than in 2004. Turnaround and maintenance costs accounted for half of the increase, as we completed major turnarounds on various upgrading units during the year. When combined with higher energy costs required in the upgrading process, our corporate average increased by 34¢/boe.

In 2006, we expect operating costs per unit to increase. This reflects the higher proportion of Canadian heavy oil production in our production mix following the 2005 Canadian property sales, coupled with industry cost pressures in all of our operating areas.

2004 vs 2003—Higher oil and gas operating costs decreased net income by $57 million

Our operating costs increased as a result of high-cost, late-life barrels in Australia, higher maintenance costs in Yemen and Canada, more workover and remediation activity in the Gulf of Mexico and the spread of fixed costs over fewer barrels.

At Masila in Yemen, flow line replacements, higher water-handling costs and more maintenance increased our corporate unit operating costs by 30¢/boe. However, these increased costs in Yemen only reduced our corporate netbacks by 5¢/boe as a result of the cost recovery mechanism in our production sharing agreement.

Operating costs in Canada were slightly lower than in 2003, but because of declining volumes, our corporate average unit costs increased by 25¢/boe.

Aspen-1 intervention costs of $12 million were expensed in 2004. They were higher than expected, as storm activity in the Gulf of Mexico extended the work. These costs, together with higher workover activities in the shallow water, contributed a 28¢/boe increase to our corporate unit costs.

The incremental North Sea barrels added 7¢/boe to our corporate average in 2004.

Australia produced its final barrel in November 2004. These expensive late-life barrels increased our corporate unit costs by 30¢/boe, but high crude prices allowed us to produce them economically.

The strength of the Canadian dollar reduced our US-dollar denominated operating costs, contributing a 25¢/boe reduction to our corporate unit costs.

Syncrude's operating costs were flat compared to 2003, but because of increased volumes, unit costs decreased 9%. Higher natural gas input costs were offset by lower maintenance costs in 2004 since there were no major turnarounds. As more expensive Syncrude barrels were a larger portion of our total corporate production in 2004, our corporate unit operating costs increased by 17¢/boe.

Depreciation, Depletion, Amortization and Impairment (DD&A)

(Cdn$/boe)	2005 Before Royalties [2]	2005 After Royalties	2004 Before Royalties [2]	2004 After Royalties	2003 Before Royalties [2]	2003 After Royalties
Conventional Oil and Gas						
Yemen	8.56	15.93	4.35	8.77	3.96	8.03
Canada [1]	9.26	11.67	9.02	11.37	9.10	11.76
United States	15.39	17.77	12.93	14.93	10.80	12.47
United Kingdom	33.25	33.25	22.44	22.44	–	–
Australia	–	–	5.82	6.31	13.31	14.46
Other Countries	6.20	6.79	9.90	10.77	17.09	22.47
Average Conventional	11.78	17.00	7.87	11.64	7.37	11.04
Synthetic Crude Oil						
Syncrude	3.08	3.12	2.75	2.85	2.50	2.53
Average Oil and Gas	**11.23**	**15.77**	**7.52**	**10.80**	**7.09**	**10.33**

Notes:

1 2003 DD&A per boe excludes the impairment charge described in Note 6 to the Consolidated Financial Statements.

2 DD&A per boe is our DD&A for oil and gas operations divided by our working interest production before royalties. We use production before royalties to monitor our performance consistent with other Canadian oil and gas companies.

2005 vs 2004—Higher oil and gas DD&A decreased net income by $308 million

Strong production volumes, new production from our North Sea assets and additional capital cost recovery from Block 51 in Yemen increased our oil and gas DD&A compared with 2004 levels. We also expensed $58 million related to unproved North Sea properties as a result of unsuccessful exploration activities.

Block 51 production in Yemen increased our corporate unit depletion by $2.21/boe from 2004 as a result of carried interest accounting for the recovery of Block 51 capital costs. Strong production and higher realized oil prices have resulted in faster recovery of capital costs we paid on behalf of the government.

Our Canadian depletion rate per unit has increased slightly compared with 2004. Reserve revisions at the end of 2004 increased our 2005 heavy oil depletion rate. This increase was somewhat offset when we stopped depleting our Canadian assets held for sale in the second quarter, but continued to recognize related production. The disposition of these assets in the third quarter changed our asset mix and reduced our average annual corporate depletion rate by 23¢/boe.

Depletion rates in the Gulf of Mexico increased following reserve revisions in late 2004. Reduced volumes offset the increase in rates with minimal impact on our overall unit rate.

North Sea depletion increased our corporate average by $2.37/boe in 2005. The depletable carrying costs of our Scott, Telford and Farragon fields include an allocation of the purchase price we paid for these assets. In addition, our North Sea depletion includes $58 million relating to a partial write-off of our purchase price allocation to unproved properties subject to unsuccessful exploration activities.

The strengthening Canadian dollar offset these increases as the depletion of our international and US assets is denominated in US dollars. This lowered our corporate average by 70¢/boe compared with 2004.

Our 2005 DD&A rate increased, reflecting additional capital cost recovery from Block 51 and new production from the North Sea.

2004 vs 2003—Lower oil and gas DD&A increased net income by $271 million

Our DD&A expense in 2003 included an impairment charge of $269 million, largely because of negative reserve revisions on our Canadian heavy oil properties. Excluding this charge from our 2003 per-unit DD&A costs, our per-unit corporate depletion rate has increased. Higher depletion from our more capital-intensive, deep-water properties in the Gulf of Mexico has increased corporate rates by 70¢/boe. However, these properties benefit from low royalties and lower unit operating costs, as most of the costs are capital in nature.

Yemen increased our corporate rate by 30¢/boe mainly because additional volumes from Block 51 slightly offset lower Masila volumes. The new North Sea volumes increased our corporate rate by 20¢/boe. Our UK depletion rate of $22.44/boe reflects the depletion of part of the acquisition cost allocated to our interests in the Scott/Telford fields on a before-tax basis.

Syncrude depletion rates increased reflecting the depletable costs of the Aurora 2 bitumen train, which came into service in late 2003.

The strong Canadian dollar lowered our depletion rate by 45¢/boe, as the depletion of our US and international assets is denominated in US dollars. As well, the depletable costs on our Canadian heavy oil properties were reduced at year-end 2003, and both Australia and Nigeria were almost fully depleted. The writedown of our Canadian heavy oil properties reduced our depletion rate by 31¢/boe, and lower volumes in Canada, Australia and Nigeria contributed to a combined reduction of 65¢/boe.

Exploration Expense [1]

Exploration success in the Gulf of Mexico and UK decreased our exploration expense to 49% of total exploration expenditures.

(Cdn$ millions)	2005	2004	2003
Seismic	53	73	62
Unsuccessful Drilling	143	125	70
Other	55	48	69
Total Exploration Expense	**251**	**246**	**201**
New Growth Exploration	456	266	267
Geological and Geophysical Costs	53	73	62
Total Exploration Expenditures	**509**	**339**	**329**
Exploration Expense as a % of Exploration Expenditures	49%	73%	61%

Note:

1 Includes exploration expense from discontinued operations. See Note 14 to our Consolidated Financial Statements.

2005 vs 2004—Higher exploration expense reduced net income by $5 million

Our 2005 exploration program was our most active in company history, as we spent more than $500 million on 20 high-potential exploration wells in our key basins. In the Gulf of Mexico, Knotty Head, drilled to a depth of 34,189 feet, encountered hydrocarbons in multiple zones. We are continuing to appraise this discovery in 2006, initially by drilling a side-track well to further delineate the reservoir. Additional delineation in 2006 is contingent on finding a rig to continue our program here. Smaller successes in the Gulf of Mexico and the North Sea will be further evaluated in 2006. Drilling equipment has been contracted for the majority of this work.

Our exploration expense includes costs associated with unsuccessful wells in the Gulf of Mexico, North Sea, offshore West Africa and Yemen. In the Gulf of Mexico, we expensed $44 million for the Vrede well. Vrede, a sub-salt prospect drilled to a total depth of 32,600 feet, encountered non-commercial quantities of hydrocarbons and was temporarily abandoned. We also wrote off costs relating to our Castleton dry hole together with trailing costs related to the 2004 Crested Butte, Wind River and Fawkes wells.

In the North Sea, exploration expense includes costs relating to Black Horse, Polecat, Bennachie and Saracen. The Black Horse and Polecat wells encountered hydrocarbons, but insufficient to warrant stand-alone development. We will continue to evaluate these reservoirs in combination with other potential development projects that may be sanctioned in the future. Bennachie was abandoned after encountering no reservoir sands in the target zone. Saracen was written off earlier in the year as an unsuccessful exploratory well.

Internationally, we expensed costs related to four unsuccessful wells on Block 51 in Yemen and we abandoned our deep-water Efere well in Nigeria, as well as our K-2 well on Block K in Equatorial Guinea.

In the UK, we wrote off Black Horse and Polecat since stand-alone developments were not feasible. However, these wells could be developed in combination with other projects.

2004 vs 2003—Higher exploration expense reduced net income by $45 million

Higher exploration expense reflected the increase in our 2004 exploration capital expenditures. We had further success at Usan on Block OPL-222, offshore Nigeria, Block 51 in Yemen and at Dawson Deep, Tobago, Wrigley and Anduin in the deep-water Gulf of Mexico. However, unsuccessful drilling included dry holes in the Gulf of Mexico, offshore Nigeria, Equatorial Guinea, and in Yemen.

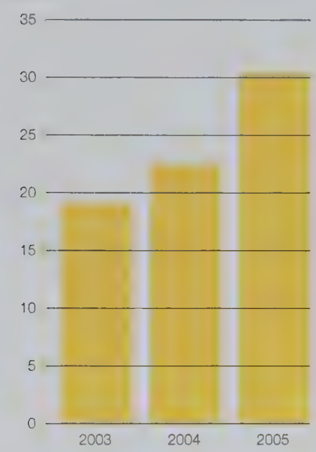
In the Gulf of Mexico, we had five dry holes: Crested Butte, Main Pass 240, Shark, Fawkes and Wind River. At our 100%-owned Crested Butte well on Green Canyon Block 242, we found oil-bearing sands in many horizons, but the volumes were not commercial, so we abandoned the well. Further work is required to determine if a sidetrack is warranted. We expensed $39 million of costs for this well in the fourth quarter. We drilled Main Pass 240 and found the objective sand wet, so we abandoned the well in December 2004. Shark was an ultra-deep-shelf gas test on South Timbalier 174 that finished drilling during the first quarter of 2004. Following our evaluation, we expensed $25 million of well costs. Fawkes and Wind River completed drilling and were abandoned in early 2005, resulting in a write-off of $13 million in 2004. Overall, dry hole and seismic costs in the Gulf of Mexico accounted for more than 50% of our exploration expense.

Dry hole costs also included the Ameena prospect on OML-115, offshore Nigeria, the Zorro-1 prospect, offshore Equatorial Guinea and two unsuccessful exploration wells on Block 51 in Yemen.

Oil & Gas and Syncrude Netbacks

Netbacks are the cash margins we receive for every equivalent barrel sold. The following table lists the sales prices, per-unit costs and netbacks for our producing assets, calculated using our working interest production before and after royalties.

Cash Netback Before Royalties
($/boe)



Before Royalties

2005 ($/boe)	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	62.07	42.42	60.26	57.83	59.96	71.00	57.97
Royalties and Other	(28.71)	(8.75)	(8.06)	–	(5.23)	(0.71)	(16.70)
Operating Expenses	(3.63)	(8.21)	(6.35)	(14.90)	(5.55)	(26.95)	(7.36)
In-country Taxes	(7.17)	–	–	–	–	–	(3.34)
Cash Netback	**22.56**	**25.46**	**45.85**	**42.93**	**49.18**	**43.34**	**30.57**

2004 ($/boe)	Yemen	Canada	US	Australia	UK	Other	Syncrude	Total
Sales	47.59	35.76	46.94	51.22	47.45	43.07	52.80	44.94
Royalties and Other	(23.98)	(7.40)	(6.29)	(4.00)	–	(3.49)	(1.84)	(13.65)
Operating Expenses	(2.80)	(7.12)	(5.30)	(32.94)	(8.26)	(3.76)	(19.89)	(6.15)
In-country Taxes	(5.82)	–	–	–	–	–	–	(2.48)
Cash Netback	**14.99**	**21.24**	**35.35**	**14.28**	**39.19**	**35.82**	**31.07**	**22.66**

2003 ($/boe)	Yemen	Canada	US	Australia	Other	Syncrude	Total
Sales	39.45	32.99	42.88	43.14	38.22	43.36	38.63
Royalties and Other	(19.98)	(7.53)	(5.91)	(3.44)	(5.69)	(0.48)	(12.14)
Operating Expenses	(2.16)	(6.00)	(4.49)	(18.60)	(7.47)	(21.96)	(5.19)
In-country Taxes	(4.73)	–	–	–	–	–	(2.06)
Cash netback	**12.58**	**19.46**	**32.48**	**21.10**	**25.06**	**20.92**	**19.24**

After Royalties

2005 ($/boe)	Yemen	Canada	US	UK	Other	Syncrude	Total
Sales	62.07	42.42	60.26	57.83	59.96	71.00	57.97
Operating Expenses	(6.75)	(10.34)	(7.33)	(14.90)	(6.08)	(27.22)	(10.34)
In-country Taxes	(13.35)	–	–	–	–	–	(4.69)
Cash Netback	**41.97**	**32.08**	**52.93**	**42.93**	**53.88**	**43.78**	**42.94**

2004 ($/boe)	Yemen	Canada	US	Australia	UK	Other	Syncrude	Total
Sales	47.59	35.76	46.94	51.22	47.45	43.07	52.80	44.94
Operating Expenses	(5.64)	(8.98)	(6.12)	(35.73)	(8.26)	(4.09)	(20.61)	(8.83)
In-country Taxes	(11.72)	–	–	–	–	–	–	(3.57)
Cash Netback	**30.23**	**26.78**	**40.82**	**15.49**	**39.19**	**38.98**	**32.19**	**32.54**

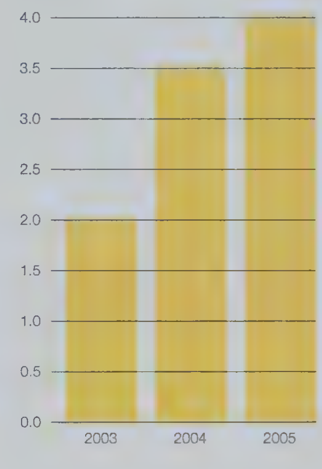
2003 ($/boe)	Yemen	Canada	US	Australia	Other	Syncrude	Total
Sales	39.45	32.99	42.88	43.14	38.22	43.36	38.63
Operating Expenses	(4.37)	(7.76)	(5.19)	(20.21)	(9.01)	(22.18)	(7.56)
In-country Taxes	(9.58)	–	–	–	–	–	(3.00)
Cash Netback	**25.50**	**25.23**	**37.69**	**22.93**	**29.21**	**21.18**	**28.07**

OIL AND GAS MARKETING

(Cdn$ millions)	2005	2004	2003
Revenue	847	608	568
Transportation	(641)	(451)	(398)
Other	(2)	(2)	(1)
Net Marketing Revenue	**204**	**155**	**169**
Marketing Contribution to Income from Continuing Operations before Income Taxes	**104**	**87**	**111**
Natural Gas			
Physical Sales Volumes [1] (bcf/d)	4.9	4.9	3.3
Transportation Capacity (bcf/d)	4.0	3.5	2.0
Storage Capacity (bcf)	30	27	18
Crude Oil			
Physical Sales Volumes [1] (mbbls/d)	510	465	479
Storage Capacity (mbbls)	580	408	–
Value-at-Risk			
Year end	24	21	21
High	28	42	31
Low	11	17	14
Average	21	29	20

Note:
1 Excludes intra-segment transactions.

Transportation Capacity
(bcf/d)



2005 vs 2004—Net marketing revenue increased net income by $49 million

Marketing delivered strong results in 2005, with net revenue of $204 million. Our gas marketing group grew their net revenue to $117 million. We achieved these results through our continued focus on an asset-based trading strategy, using our transportation and storage capacity to take advantage of seasonal and locational pricing differences and market inefficiencies.

While 2005 was a profitable year, it was also volatile with hurricane activity in the Gulf of Mexico disrupting gas supply and infrastructure. This volatility caused us to recognize losses in the third quarter on financial contracts hedging our physical assets. However, we were able to recognize gains on our physical assets in the fourth quarter as we used our transportation capacity and sold gas from storage. This allowed us to recoup our third quarter losses and recognize $175 million of net revenue in the fourth quarter. We also generated profits from financial contracts that captured time and location spreads.

Gas marketing contributed 57% of marketing net revenue in 2005.

Our crude oil marketing group contributed $65 million of net revenue in 2005, an increase of 33% over 2004. Similar to prior years, we continued to capitalize on forward prices, as well as differences in crude qualities. In particular, in 2005, we took advantage of contango (rising forward month prices) by successfully pricing our purchases lower than our sales, and by financially trading calendar spreads. We also captured profits around quality spreads by diverting crude oil, or by blending to enhance the crude quality, and attract higher prices.

2004 vs 2003—Net marketing revenue decreased net income by $14 million

Marketing had another exceptional year in 2004 with net revenue of $155 million. Gas marketing contributed $95 million to net revenue from asset-based trading, our energy services business, and from transportation and commodity contracts acquired on favourable terms.

During 2004, we took advantage of market inefficiencies and seasonal variations. In particular, our transportation and storage capacity gave us the flexibility to capitalize on weather events and move gas to where it was needed most. We also held financial contracts that enabled us to capture trading profits around time and location spreads.

North American crude oil contributed $25 million to net revenue as varying degrees of backwardation (declining forward month prices) in the forward price curve throughout the year enabled us to capitalize on calendar spreads. In addition, we took advantage of quality spreads and arbitrage opportunities to capture favourable price differences.

International crude oil contributed $24 million, three times higher than in 2003. Throughout 2004, we successfully capitalized on the pricing of purchases relative to sales, as we took advantage of backwardation in the forward price curve.

Composition of Net Marketing Revenue

(Cdn$ millions)	2005	2004
Trading Activities	168	133
Non-Trading Activities	36	22
Total Net Marketing Revenue	**204**	**155**

Trading Activities

We mark-to-market all derivative contracts not designated as hedges. The gain or loss is recorded in marketing and other income.

In marketing, we enter into contracts to purchase and sell crude oil and natural gas. We also use financial and derivative contracts, including futures, forwards, swaps and options for hedging and trading purposes.

We account for all derivative contracts not designated as hedges for accounting purposes, using mark-to-market accounting, and record the net gain or loss from their revaluation in marketing and other income. The fair value of these instruments is included with accounts receivable or payable. They are classified as long-term or short-term based on their anticipated settlement date.

We value derivative trading contracts daily using:

- actively quoted markets such as the New York Mercantile Exchange and the International Petroleum Exchange; and
- other external sources such as the Natural Gas Exchange, independent price publications and over-the-counter broker quotes.

Fair Value of Derivative Contracts

At December 31, 2005, the fair value of our derivative contracts not designated as hedges totalled $169 million (2004—$93 million). Below is a breakdown of this fair value by valuation method and contract maturity.

	Maturity				
(Cdn$ millions)	< 1 year	1-3 years	4-5 years	> 5 years	Total
Prices					
Actively Quoted Markets	(29)	14	(18)	(3)	(36)
From Other External Sources	90	100	12	3	205
Based on Models and Other Valuation Methods	–	–	–	–	–
Total	**61**	**114**	**(6)**	**–**	**169**

More than 35% of our unrealized fair value relates to contracts that will settle in 2006.

These unrealized fair values will be realized over time as the related contracts settle. Until then, the value of the contracts will vary with forward commodity prices. While forward prices vary, the value of our contracts only varies to the extent they are economically exposed or unprotected. As most of our unrealized value is not economically exposed, we expect to realize most of this fair value.

More than 35% of the unrealized fair value relates to contracts that will settle in 2006. Contract maturities vary from a single day up to eight years. Those maturing beyond one year primarily relate to North

American natural gas positions. The relatively short maturity of our contracts, the high quality of our valuations and the limited economic exposure combine to lower our portfolio risk.

Included in the derivative contracts that we mark-to-market are financial contracts that act as economic hedges of our physical transportation and storage capacity. For economic purposes, we monitor the fair value of our transportation and storage capacity as well as any commodities we have in storage, but we do not record this value in income until realized. At the end of 2005, the unrecognized fair value of these transportation and storage positions was $29 million.

We have designated certain derivative contracts as accounting cash flow hedges of the future sale of our gas in storage. Mark-to-market gains and losses on these designated contracts are excluded from income until the underlying inventory is sold. At December 31, 2005, we had $35 million of unrecognized losses on these derivative contracts. These contracts have been valued from actively quoted markets and will settle within 12 months.

Changes in Fair Value of Derivative Contracts

(Cdn$ millions)	Contracts Outstanding at Beginning of Year	Contracts Entered into During Year	Total
Fair Value at December 31, 2004	93	–	93
Change in Fair Value of Contracts	92	90	182
Net Losses (Gains) on Contracts Closed	(47)	(59)	(106)
Changes in Valuation Techniques and Assumptions [1]	–	–	–
Fair Value at December 31, 2005	**138**	**31**	**169**
Unrecognized Losses on Hedges of Future Sale of Gas Inventory at December 31, 2005			(35)
Total Outstanding at December 31, 2005			**134**

Note:
1 Our valuation methodology has been applied consistently year-over-year.

Total Carrying Value of Derivative Contracts

(Cdn$ millions)	2005	2004
Current Assets	382	177
Non-Current Assets	232	91
Total Derivative Contract Assets	**614**	**268**
Current Liabilities	321	129
Non-Current Liabilities	124	46
Total Derivative Contract Liabilities	**445**	**175**
Total Derivative Contract Net Assets [1]	**169**	**93**

Note:
1 Excludes derivative contracts that have been designated as accounting hedges.

Non-Trading Activities

We enter into fee-for-service contracts related to transportation and storage of third-party oil and gas. We also earn income from our power generation facility. We earned $36 million from our non-trading activities in 2005 (2004—$22 million).

In 2004 and 2005, we increased our transportation capacity and were paid to assume future obligations associated with the capacity. We have $28 million of deferred revenue on our balance sheet to recognize the liability associated with these obligations. We are amortizing this deferred revenue to earnings as the capacity is used.

We enter into fee-for-service contacts related to transportation and storage, and increased our transportation capacity in 2004 and 2005.

CHEMICALS

(Cdn$ millions)	2005	2004	2003
Net Sales	398	378	375
Sales Volumes (thousand short tons)			
Sodium Chlorate	493	506	478
Chlor-alkali	400	403	396
Operating Profit [1]	136	105	95
Operating Margin [2]	34%	28%	25%
Chemicals Contribution to Income from Continuing Operations Before Income Taxes	37	40	28
Capacity Utilization	96%	95%	95%

Notes:
1 Total revenues less operating costs, transportation and other.
2 Operating profit divided by net sales.

We monetized a portion of our chemicals business in 2005, retaining a 61.4% indirect interest.

Despite lower sales volumes, strong chlor-alkali prices and higher margins generated strong 2005 results for chemicals.

2005 vs 2004 — Higher chemicals operating profit increased net income by $31 million

In the third quarter of 2005, we monetized a portion of our chemicals business by creating the Canexus Income Fund through an initial public offering (IPO), which raised net proceeds of $301 million. Canexus Income Fund invested the offering proceeds into Canexus Limited Partnership, which also raised US$167 million ($200 million) of bank debt. Canexus Limited Partnership used the proceeds from Canexus Income Fund's IPO and the bank debt, together with the issuance of 50.5 million exchangeable units of the Canexus Limited Partnership to Nexen, to purchase our chemicals operations. The exchangeable units we hold had a market value of $442 million at December 31, 2005. We have retained a 61.4% indirect interest in the chemicals operations through our investment in Canexus Limited Partnership, and we recorded a gain of $193 million on the dilution of our interest.

Despite lower sales volumes, strong chlor-alkali prices and higher margins generated strong results for the chemicals business. Sodium chlorate volumes decreased compared with 2004 as a result of our decision in early 2005 to forego low-margin business consistent with our restructuring effort and the closure of our Amherstburg, Ontario plant. Sales and operations from the Brazil plant remained strong as a result of continued strong demand from Aracruz Cellulose, our primary customer in Brazil, and an expanded presence in the merchant market.

The weaker US dollar put pressure on our US-dollar denominated sales, reducing net sales by $13 million. During 2005, we purchased US-dollar foreign currency call options to mitigate our exposure to the weakening dollar. We generated $4 million of income as a result of these call options.

Our chemicals contribution was reduced by $12 million for an impairment charge relating to our chemicals plant in Amherstburg, which was closed in the third quarter of 2005.

2004 vs 2003 — Higher chemicals operating profit increased net income by $10 million

Our chemicals business benefited from strong demand for bleaching chemicals in North and South America. Solid North American demand for chlor-alkali and sodium chlorate throughout 2004 resulted in strong pricing for our products. However, a stronger Canadian dollar lowered our sales by $15 million in 2004, as most of our sales are denominated in US dollars, while our costs are primarily in Canadian dollars.

We successfully completed the expansion of our plant in Brandon, Manitoba in October 2004, making it the largest sodium chlorate production facility in the world. This expansion minimizes our exposure to the rising electricity costs faced in other provinces, as Manitoba enjoys a stable, regulated electricity market.

At our Brazil plant, production improvements enabled us to take advantage of strong market demand.

CORPORATE EXPENSES

General and Administrative (G&A) [1]

(Cdn$ millions)	2005	2004	2003
General and Administrative Expense before Stock Based Compensation	302	206	176
Stock Based Compensation [2]	490	93	14
Total General and Administrative Expense	**792**	**299**	**190**

Notes:
1 Includes G&A from discontinued operations. See Note 14 to our Consolidated Financial Statements.
2 Includes tandem option plan, stock options for our US-based employees and stock appreciation rights.

2005 vs 2004—Higher costs reduced net income by $493 million

Our stock-based compensation expense in 2005 reflects the significant increase in the price of our common shares. Our share price increased 128% from $24.35 to $55.42, adding more than $8 billion of shareholder value. The expense represents approximately 6% of the increase in shareholder value. Notwithstanding this increase in our share price, cash payments to employees under our stock-based compensation programs only amounted to $79 million.

Our stock-based compensation expense increased $397 million in 2005, as our share price increased 128%.

Our growing international presence and the expansion of our businesses increased our G&A costs during the year. Costs reflect more employees, additional travel, and higher compliance and governance costs, combined with increased variable incentive compensation stemming from our record results. We also incurred additional costs related to our disposition activities and the integration of our North Sea operations acquired in late 2004.

2004 vs 2003—Higher costs reduced net income by $109 million

During the second quarter, our shareholders approved the modification of our stock option plan to a tandem option plan, creating a one-time G&A expense of $82 million.

Other G&A costs include increased variable incentive compensation in light of our record results, more employees because of increased capital investment, and higher regulatory compliance costs, including those associated with our Sarbanes-Oxley project on internal control documentation.

Interest

(Cdn$ millions)	2005	2004	2003
Interest [1]	275	194	212
Less: Capitalized	(178)	(51)	(43)
Net Interest Expense	**97**	**143**	**169**
Effective Rate	6.4%	6.6%	7.2%

Note:
1 Includes dividends on preferred securities in 2004 and 2003. See Note 1(u) to our Consolidated Financial Statements.

2005 vs 2004—Lower net interest expense increased net income by $46 million

We acquired our North Sea assets in late 2004. We partially financed this acquisition with US$1 billion of new long-term debt, which increased our interest costs by $87 million in 2005. Interest expense also increased $3 million relating to the Canexus debt consolidated with our results. However, the stronger Canadian dollar lowered our US-dollar denominated interest by $12 million. During the last two years, we have taken advantage of declining interest rates by replacing our higher-cost preferred securities with new long-term debt at lower rates.

Our effective interest rate has dropped the last two years as we replaced higher-cost preferred securities with lower-cost long-term debt.

We capitalize interest on our major development projects in the North Sea, Syncrude, Long Lake and Block 51 in Yemen based on our average borrowing rate. Capitalized interest grew primarily from the increased investment in the North Sea Buzzard project and additional spending at Long Lake. We expect capitalized interest to continue increasing as we invest additional capital on these projects prior to their completion in 2006 and 2007.

2004 vs 2003—Lower net interest expense increased net income by $26 million

In late 2003 and early 2004, we refinanced our preferred securities with lower-cost debt. We also repaid US$225 million of bonds in February 2004. These two events reduced interest expense in 2004. In December 2004, we drew US$1.5 billion on our acquisition credit facilities to provide financing for our UK North Sea acquisition, increasing our interest expense by $5 million. The strong Canadian dollar lowered our US-dollar denominated interest expense by $6 million.

Capitalized interest increased over 2003 from additional capital spending at our major development projects including Syncrude Stage 3 expansion and Long Lake in Canada, Block 51 in Yemen and Buzzard in the North Sea.

Our 2005 effective tax rate decreased to 9%, as we revalued our future income tax liabilities after dispositions and recognized a recovery of $229 million.

Income Taxes

(Cdn$ millions)	2005	2004	2003
Current	339	248	210
Future	(229)	119	(57)
Total Provision for Income Taxes	**110**	**367**	**153**
Disclosed as:			
Provision for Income Taxes—Continuing Operations	239	317	97
Provision for Income Taxes—Discontinued Operations [1]	(129)	50	56
Total Provision for Income Taxes	**110**	**367**	**153**
Effective Rate	9%	32%	21%

Note:

1 See Note 14 to our Consolidated Financial Statements.

2005 vs 2004—Effective tax rate decreases from 32% to 9%

The recovery of future taxes payable of $229 million is attributable to the disposition of our oil and gas producing properties in Canada and the sale of our chemicals business to the Canexus Limited Partnership. As a result of the dispositions, we revalued our future income tax liabilities for the change in the underlying book and tax values. This revaluation resulted in the reduction of our future income tax liabilities. In addition, the disposition gains were taxed at lower capital gains tax rates. Removing the tax impact of the dispositions, the effective tax rate for our continuing operations was 32%.

In a recent pre-budget announcement, the UK government said it intends to increase the 10% supplemental charge on income from oil and gas activities to 20% effective January 1, 2006. This increase is subject to the introduction of legislation. If this announcement becomes law, we expect our effective tax rate to increase above 32%.

Current income taxes include cash taxes in Yemen of $296 million (2004—$227 million; 2003—$201 million). Our current income tax provision also includes cash taxes in Colombia, federal and state taxes in the US and capital taxes in Canada.

2004 vs 2003—Effective tax rate increases from 21% to 32%

In 2004, a 1% reduction in Alberta's corporate income tax rate resulted in a $15 million recovery of future income taxes. The low effective tax rate for 2003 resulted from reduced federal tax rates for Canadian resource activities, which generated a recovery of future income taxes of $76 million.

Other

(Cdn$ millions)	2005	2004	2003
Gain on Dilution of Interest in Chemicals Business	193	–	–
Gain on Disposition of Oil and Gas Assets included as Discontinued Operations	225	–	–
Increase (Decrease) in Fair Value of Crude Oil Put Options	(196)	56	–

As a result of the sale of our chemicals business to the Canexus Limited Partnership, we recorded a gain on the dilution of our interest from 100% to 61.4% of $193 million. Our gain on the sale of Canadian oil and gas properties in Alberta, British Columbia and Saskatchewan was $225 million. This gain is net of losses attributable to pipeline contracts and fixed-price gas contracts associated with these properties that we retained, but no longer use in our oil and gas business.

Following our North Sea acquisition in late 2004, we purchased put options on 60,000 bbls/d of oil production for 2005 and 2006 to ensure base cash flow in those years while we invest in our major development projects. These options created an average floor price for this production of US$43.17/bbl in 2005 and US$38.17/bbl in 2006. Accounting rules require that these options be recorded at fair value throughout their term. As a result, changes in forward crude oil prices cause gains or losses to be recorded on these options at each period end. A gain of $56 million was recorded in the fourth quarter of 2004, bringing the fair value of these options to $200 million. During 2005, a significant increase in forward crude prices resulted in a value loss of $196 million. The carrying value of these options at December 31, 2005 was $4 million.

IMPACT OF FOREIGN EXCHANGE ON OPERATIONS

The strengthening Canadian dollar relative to the US dollar reduced cash flow from operating activities by $251 million and our net income by $116 million. This is because our foreign revenues and realized commodity prices, referenced in US dollars, were lower when translated to Canadian dollars. However, we benefit to the extent that our foreign operating costs and capital expenditures are reduced when translated. In addition, most of our fixed-rate debt is denominated in US dollars so the Canadian dollar equivalent of this debt is reduced with a strengthening Canadian dollar. We have designated our US-dollar denominated debt as a hedge of our net investment in foreign operations. As a result, unrealized foreign exchange gains on the translation of this debt are not included in our net income, but are included as cumulative foreign currency translation adjustments on our balance sheet. The tax effect of unrealized foreign exchange gains on our US-dollar debt results in an increase to our future income tax liabilities, which is offset by a decrease to our cumulative translation adjustment account.

A stronger Canadian dollar negatively impacts our realized commodity prices and positively impacts our US-dollar denominated debt, operating costs and capital expenditures.

OUTLOOK FOR 2006

In 2006, we plan to invest $2.9 billion in value-generating capital projects. Approximately 45% of this capital will be invested in major development projects. These include Buzzard, Long Lake, coal bed methane and Syncrude Stage 3, all planned to come on stream in 2006 and 2007. We are also directing 10% of our 2006 capital to early stage development projects expected to contribute production and cash flow beyond 2006. These include development of additional CBM lands, enhanced oil recovery projects, additional phases of oil sands and existing North Sea discoveries. We have allocated 21% of our capital to high-quality exploration opportunities in our growth areas. The remaining 24% of the 2006 capital will be invested to exploit potential in our existing producing assets and in other corporate assets.

Details of our 2006 capital investment program are included in the Capital Investment section of the MD&A.

In 2006, we plan to invest $2.9 billion in value-generating capital projects. See page 32 for more details.

In 2007, we expect production after royalties to grow by more than 50% over current volumes.

Daily Production

Even after selling Canadian production in mid-2005, we expect our 2006 production before royalties to be similar to 2005. Our annual production for 2006 is expected to average between 220,000 boe/d and 240,000 boe/d before royalties, 165,000 boe/d and 180,000 boe/d after royalties, as follows:

2006 Estimated Production

(mboe/d)	Before Royalties	After Royalties
Gulf of Mexico	40 – 45	33 – 38
North Sea	25 – 30	25 – 30
Yemen	90 – 100	50 – 55
Canada	35 – 40	27 – 31
Syncrude	20 – 22	18 – 20
Other International	6 – 7	5 – 6
Total	**220 – 240**	**165 – 180**

We expect our production will grow significantly in 2007, as we gain a full year of high-margin production from Buzzard and Syncrude Stage 3, and Long Lake synthetic volumes come on stream. Production after royalties is expected to increase by more than 50% in 2007, generating strong growth in our operating margins and cash flow, assuming commodity prices remain strong.

We expect to generate more than $2.6 billion in cash flow from operating activities in 2006. A US$1/bbl change in WTI will impact cash flow by $40 million.

Cash Flow and Sensitivities

We expect to generate more than $2.6 billion in cash flow from operating activities in 2006 (before site restoration and geological and geophysical expenditures), assuming the following:

WTI (US$/bbl)	55.00
NYMEX Natural Gas (US$/mmbtu)	9.25
US to Canadian Dollar Exchange Rate	0.85

Changes in actual commodity prices and exchange rates impact our annual cash flow from operating activities as follows:

(Cdn$ millions)	
WTI—US$1 Change	40
NYMEX Natural Gas—US$0.10 Change	7
Exchange Rate—$0.01 Change	25

We expect our chemicals and marketing businesses to continue generating solid contributions to cash flow and net income in 2006. We continue to see strong demand and high prices for our chemical products. Solid North American energy markets are expected in 2006, which will enable our marketing group to profit from our asset-based trading strategy. Our marketing group plans to expand into European markets with the addition of crude oil volumes from Buzzard in the North Sea.

LIQUIDITY AND CAPITAL RESOURCES

Capital Structure

(Cdn$ millions)	2005	2004
Net Debt [1]		
Bank Debt	171	1,993
Public Senior Notes	2,980	1,813
Senior Debt	3,151	3,806
Subordinated Debt	536	553
Total Debt	3,687	4,359
Less: Cash and Cash Equivalents	(48)	(73)
Less: Restricted Cash	(70)	–
	3,569	4,286
Less: Non-Cash Working Capital [2]	72	(67)
Total Net Debt	**3,641**	**4,219**
Shareholders' Equity [3]	**4,008**	**2,867**

Notes:

1 Includes all of our debt and is calculated as long-term debt less working capital.

2 Excludes short-term borrowings.

3 At January 31, 2006, there were 261,614,723 common shares and US$460 million of unsecured subordinated securities outstanding. These subordinated securities may be redeemed by issuing common shares at our option after November 8, 2008. The number of shares issuable depends on the common share price on the redemption date.

Net Debt

We use net debt as a key indicator of our leverage and to monitor the strength of our balance sheet. Net debt is directly related to our operating cash flows, capital investment activities and disposition programs. We ended the year with net debt of $3.6 billion, a decrease of $0.6 billion from 2004.

During the year, we sold certain Canadian oil and gas producing assets, monetized a portion of our chemicals business and issued more than US$1 billion of long-term debt. These funds were used to repay the acquisition credit facilities that we used to finance purchase of North Sea assets in late 2004, and to partially fund our 2005 investment program. Our cash flow from operating activities funded the balance of our investment program.

In 2005, we issued more than US$1 billion of long- [illegible] proceeds from asset dispositions. These funds reduced debt incurred on the North Sea acquisition and partially funded our capital programs.

The year-over-year change in our net debt results from:

(Cdn$ millions)	2005	2004
Capital Investments (including 2004 North Sea Acquisition)	2,638	4,264
Cash Flow from Operating Activities	(2,143)	(1,606)
Excess of Capital Investment over Cash Flow	495	2,658
Net Proceeds on Disposition of Oil and Gas Properties	(911)	(34)
Net Proceeds from Canexus Initial Public Offering	(301)	–
Dividends on Common Shares	52	52
Issue of Common Shares (Primarily Exercise of Employee Stock Options)	(58)	(124)
Foreign Exchange Translation of US-dollar Debt and Cash	(113)	(78)
Increase in Current Obligation Related to Stock Based Compensation	321	91
Other	(63)	(36)
Increase (Decrease) in Net Debt	**(578)**	**2,529**

The decrease in our net debt has improved our net-debt-to-cash-flow leverage, while our lower interest coverage reflects the additional interest incurred to finance our North Sea acquisition, as follows:

(times)	2005	2004	2003
Net Debt to Cash Flow from Operating Activities	1.7	2.6	1.2
Interest Coverage [1]	9.8	11.9	10.1

Note:

1 Earnings before interest, taxes, DD&A and exploration expense divided by interest expense (before capitalized interest).

Our business strategy is focused on value-based growth through full-cycle exploration and development, supplemented by strategic acquisitions when appropriate. We have leveraged our balance sheet in the past to accomplish our growth strategy, as most of our projects have long-cycle times, requiring significant amounts of capital to be invested prior to generating cash flows. Historically, we have been successful with this strategy as we used leverage to:

- develop the Masila project in Yemen in 1993;
- acquire Wascana in 1997;
- repurchased 20 million common shares in 2000;
- acquire the remaining interest in Aspen in 2003; and
- acquire the Buzzard project and other key assets in the North Sea in 2004.

Each time, we exceeded our internal net debt to cash flow target band; however, we successfully brought our leverage down once these projects began generating cash flow. In 2005, we reduced our net debt by selling producing assets in Canada and monetizing a portion of our chemicals business. Our future liquidity is expected to strengthen and our net debt is expected to be reduced further when our Buzzard and Long Lake projects come on stream and contribute significant free cash flow in 2007 and beyond.

Change in Working Capital

Receivables and payables increased primarily in our marketing operations, reflecting higher commodity prices.

(Cdn$ millions)	2005	2004	Increase/ (Decrease)
Cash and Cash Equivalents	48	73	(25)
Restricted Cash	70	–	70
Accounts Receivable	3,151	2,100	1,051
Inventories and Supplies	504	351	153
Accounts Payable and Accrued Liabilities	(3,710)	(2,377)	(1,333)
Other	(17)	(7)	(10)
	46	**140**	**(94)**

Higher commodity prices impacted our non-cash working capital by increasing the receivables and payables attributable to our marketing group. Inventory held by our marketing operation was higher at year end from higher gas prices that increased the cost of our inventoried gas. Our payables have increased since 2004 because of the higher accrued liability of our stock-based compensation programs.

Liquidity

We manage our capital structure to maintain flexibility so we can fund our capital program through the commodity price cycles.

We generally rely on operating cash flows to fund capital requirements and provide liquidity. We build our opportunity portfolio to provide a balance of short-term, mid-term, and longer-term growth. Given the long cycle-time of some of our development projects and the volatility of commodity prices, it is not unusual in any given year for capital expenditures to exceed our cash flow. When this happens, we draw on available credit facilities, as we maintain significant committed credit facilities. At December 31, 2005, we had committed term credit facilities of $2.4 billion that are available until 2010. At year end, $250 million of these facilities were utilized to support letters of credit. We also had $732 million of uncommitted, unsecured credit facilities, of which $468 million was utilized to support letters of credit.

From time to time, we access the capital markets to meet our financing needs. We also use various financial instruments to minimize our exposure to fluctuations in foreign exchange and commodity prices. For example, we purchased WTI put options for 2005 and 2006 to mitigate liquidity risk and reduce cash flow volatility. Overall, we manage our capital structure to maintain flexibility so we can fund our capital programs throughout the highs and lows of the price cycles inherent in the oil and gas business.

The table on the following page shows how we use our cash flow from operating activities to fund our investing activities. When our operating cash flows exceed our investment requirements, we generally pay down debt. We borrow or issue equity to fund investment requirements that exceed our operating cash flow.

(Cdn$ millions)	2005	2004	2003	2002	2001
Cash Flow from Operating Activities	2,143	1,606	1,405	1,250	1,496
Cash Flow from Investing Activities	(1,864)	(4,013)	(1,219)	(1,569)	(1,469)
	279	(2,407)	186	(319)	27
Cash Flow from Financing Activities	(274)	1,426	1,006	329	(100)
	5	**(981)**	**1,192**	**10**	**(73)**

In 2001 and 2002, we began to invest significantly in two deep-water Gulf of Mexico projects (Aspen and Gunnison), our Syncrude expansion and our Long Lake project. We used our cash flow in 2001 and accessed public debt markets in 2002 to fund these investments. In 2003, Aspen contributed significantly to our cash flow and in late 2003, we pre-funded debt repayments by raising more than $1 billion in senior and subordinated debt. We used these funds in 2004 to repay higher cost debt, and coupled with acquisition credit facilities, acquired the North Sea assets. In 2005, we used our cash flow and the proceeds from asset dispositions to fund our capital program and repay debt.

Our marketing business also requires liquidity to support its asset-based trading strategy. Liquidity requirements include cash for working capital, cash or credit lines to fund collateral requirements and risk capital to absorb unexpected market or credit losses. The commercial agreements our marketing business enters into often include financial assurance provisions that allow Nexen and our counterparties to effectively manage credit risk. These agreements typically require posting of collateral when adverse credit-related events occur, such as a reduction in credit ratings. In evaluating our liquidity requirements, we consider the current requirements of our marketing business as well as additional collateral or other payments that could be required in the event of reductions in our credit ratings.

Future Liquidity

Our future liquidity is primarily dependent on cash flows generated from our operations, existing committed credit facilities and our ability to access debt and equity markets. Assuming WTI of US$55/bbl, we expect our 2006 capital investment program and dividend requirements to exceed our cash flow by more than $350 million. We plan to fund this shortfall by drawing on our unused committed credit facilities. In late 2006, we will also repay $93 million of medium term notes that become due, which we expect to fund using our committed credit facilities.

In 2006, we expect our capital program and dividend requirements to exceed our cash flow. We plan to fund this shortfall using committed credit facilities.

Our cash flow is sensitive to changes in commodity prices and exchange rates. For 2006, we expect cash flow of more than $2.6 billion (before remediation and geological and geophysical expenditures) assuming:

WTI (US$/bbl)	55.00
NYMEX Natural Gas (US$/mmbtu)	9.25
US to Canadian Dollar Exchange Rate	0.85

Changes in commodity prices and exchange rates will impact our cash flow and our borrowing requirements. The impact of a variance in any one of the above assumptions on our cash flow is described in the Outlook for 2006 section on page 55.

We are in the midst of developing major projects including Buzzard in the North Sea, Long Lake and our coal bed methane project in the Fort Assiniboine area of Alberta. Our anticipated spending on these projects in 2006 and 2007 is as follows:

Much of our planned capital spending over the next two years relates to our Buzzard, Long Lake and coal bed methane projects.

(Cdn$ millions)	
2006	1,080
2007	330
Total Capital Investment	**1,410**

Given our reliance on cash flows to fund these projects, we implemented a cash flow protection strategy using WTI crude oil put options in late 2004 for 2005 and 2006. For 2006, these put options provide us

with an annual average WTI floor price of US$38.17 on 60,000 bbls of oil per day. This strategy reduces the downside risk to our future cash flows in 2006 if commodity prices were to fall when our capital requirements are high, yet still allows us to realize all price upside.

Our Buzzard project creates foreign currency exposure as a portion of the capital costs are denominated in British pounds and Euros, while our revenue stream is primarily US dollars. To reduce our exposure to fluctuations in these currencies relative to the US dollar, we purchased foreign currency call options in early 2005 that effectively set a ceiling on most of our British pound and Euro spending exposure from March 2005 to the end of 2006.

If required, we have more than $2 billion in committed credit facilities and a US$1.5 billion shelf prospectus available.

While these development projects lack exploration risk, they are subject to other risks including higher than anticipated capital costs or delayed start-up. We maintain undrawn committed credit facilities to manage this risk. In addition to our operating cash flows and our undrawn committed credit facilities, we have a US$1.5 billion shelf prospectus available in the US and Canada.

At December 31, 2005, the average term to maturity of our long-term debt was 20.5 years. We have the following debt maturities during the next five years:

(Cdn$ millions)	2006	2007	2008	2009	2010
Term Credit Facilities [1]	–	–	–	–	–
Canexus LP Term Credit Facilities	–	–	–	171	–
Debentures	93	–	–	–	–
Medium Term Notes	–	150	125	–	–
Total	**93**	**150**	**125**	**171**	**–**

Note:
1 $2.4 billion available until 2010.

With our expected cash flow streams, commodity price and foreign exchange hedging strategies, current levels of liquidity, and access to debt and equity markets, we expect to have no difficulties funding our planned capital programs, dividend requirements and debt repayments, or meeting other obligations that may arise from our oil and gas, chemicals and marketing operations.

We expect to declare common share dividends of $0.20 per share in 2006.

In 2005, we declared common share dividends of $0.20 per share (2004—$0.20, 2003—$0.163). We expect to declare common share dividends of $0.20 per share in 2006.

Contractual Obligations, Commitments and Guarantees

We assume various contractual obligations and commitments in the normal course of our operations and financing activities. We have considered these obligations and commitments in assessing our cash requirements, as noted in the above discussion of future liquidity. They include:

		Payments			
(Cdn$ millions)	Total	<1 year	1-3 years	4-5 years	>5 years
Long-Term Debt	3,687	93	275	171	3,148
Interest on Long-Term Debt	5,086	225	420	402	4,039
Operating Leases [1]	272	33	63	55	121
Capital Leases	113	2	10	10	91
Energy Commodity Contract Liabilities	445	321	102	20	2
Transportation and Storage Commitments [1]	888	440	230	102	116
Work Commitments and Purchase Obligations [2]	2,143	1,229	568	261	85
Asset Retirement Obligations	1,471	21	35	32	1,383
Other	6	1	2	2	1
Total	**14,111**	**2,365**	**1,705**	**1,055**	**8,986**

Notes:
1 Payments for operating leases and transportation and storage commitments are deducted from our cash flow from operating activities.
2 Some of these payments relate to work commitments cancellable at our option without penalties or additional fees.

Contractual obligations can be financial or non-financial. Financial obligations are known future cash payments that we must make under existing contracts, such as debt and lease arrangements. Non-financial obligations are contractual obligations to perform specified activities such as work commitments. Commercial commitments are contingent obligations that become payable only if certain pre-defined events occur.

- Long-term debt amounts are included on our December 31, 2005 Consolidated Balance Sheet.
- Operating leases include the minimum lease payment obligations associated with leases for office space, rail cars, vehicles and our processing agreement with Shell that allows our Aspen production to flow through Shell's processing facilities at the Bullwinkle platform. The terms of the processing agreement give Shell an annual option to take payment in cash or in kind. For 2006, Shell has elected to take payment in kind, so the 2006 obligation has been excluded from this table. Instead, it is shown as a royalty and excluded from reserves and production.
- Capital leases include pipeline commitments primarily related to future production at Long Lake.
- Energy commodity contract liabilities include the purchase and sale of physical quantities of oil and natural gas, and financial derivatives used to manage our exposure to commodity prices. For contracts where the price is based on an index, the amount is based on forward market prices at December 31, 2005. For certain contracts, we may net settle.
- Work commitments include non-discretionary capital spending related to drilling, seismic, construction of facilities and other development commitments in our international operations, and includes Long Lake ($422 million), the Buzzard project in the North Sea ($592 million) and at Block 51 in Yemen ($88 million). The timing of certain payments is difficult to determine with certainty. The table has been prepared using our best estimates; the remainder of our 2006 capital investment is discretionary.
- We also have included work commitments relating to drilling rigs, which have been contracted to work for us in the North Sea and Gulf of Mexico, totalling $602 million over the next five years.
- We have $1,471 million of undiscounted asset retirement obligations. As of December 31, 2005, the discounted value ($611 million) of these estimated obligations has been provided for in our consolidated financial statements (including $21 million of current liabilities). The timing of any payments is difficult to determine with certainty, and the table has been prepared using our best estimates.
- We have unfunded obligations under our defined benefit pension and post retirement benefit plans of $86 million (of which $9 million relates to Canexus), and our share of Syncrude's unfunded obligation is $51 million. Our $86 million obligation includes $43 million that is unfunded as a result of statutory limitations. These obligations are backed by irrevocable letters of credit.
- We have excluded obligations on our stock option and stock appreciation rights programs as the amount and timing of cash payments are indeterminable.
- We have excluded our normal purchase arrangements as they are discretionary and are reflected in our expected cash flow from operating activities and our expected capital expenditures for 2006.
- We have excluded our future income tax liabilities as the amount and timing of any cash payments for income taxes are based primarily on taxable income for each fiscal year in the various jurisdictions in which we operate.

Our long-term debt and interest accounts for more than 60% of our contractual obligations and commitments

We have entered into a long-term supply agreement under which we are committed to deliver 35,000 bbls/d of heavy crude oil at market prices beginning mid-2008 for ten years.

From time to time, we enter into contracts that require us to indemnify parties against possible claims, particularly when these contracts relate to the sale of assets. On occasion, we provide indemnifications to the purchaser. Generally, a maximum obligation is not stated; therefore, the overall maximum amount cannot be reasonably estimated. We have not made any significant payments related to these indemnifications. Our Risk Management Committee actively monitors our exposure to the above risks and obtains insurance coverage to satisfy potential or future claims as necessary. We believe these matters would not have a material adverse effect on our liquidity, financial condition or results of operations.

Credit Ratings

Currently, our senior debt is rated BBB- by Standard & Poor's (S&P), Baa2 by Moody's Investor Service, Inc. (Moody's) and BBB by Dominion Bond Rating Service (DBRS). In addition, S&P and DBRS currently rate our outlook as stable while Moody's has a negative outlook. Our strong financial results, ample liquidity and financial flexibility continue to support our credit ratings.

Financial Assurance Provisions in Commercial Contracts

The commercial agreements our marketing group enters into often include financial assurance provisions that allow Nexen and our counterparties to effectively manage credit risk. The agreements normally require posting of collateral when adverse credit-related events occur such as a reduction in credit ratings. Based on the contracts in place and commodity prices at December 31, 2005, we could be required to post collateral of up to $1.1 billion if we were downgraded to non-investment grade. These obligations are already reflected on our balance sheet. The posting of collateral merely accelerates the payment of such amounts. Just as we may be required to post collateral in the event of a downgrade below investment grade, we have similar provisions in many of our contracts that allow us to demand certain counterparties post collateral with us if they are downgraded to non-investment grade.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements that would have a material adverse effect on our liquidity, consolidated financial position or results of operations. We use operating leases in the normal course of business as disclosed in Contractual Obligations, Commitments and Guarantees on page 60 and in Note 15 to the Consolidated Financial Statements in Item 8, which is incorporated herein by reference.

Contingencies

We have no contingencies that would have a material adverse effect on our liquidity, consolidated financial position or results of operations. See Note 15 to the Consolidated Financial Statements in Item 8, which is incorporated herein by reference for a discussion of our contingencies.

RISK FACTORS

Our operations are exposed to various risks, some of which are common to others in our industry and some of which are unique to our operations. We attempt to mitigate the risks to an acceptable level but many of these risks are beyond our control so we cannot provide any assurances that they will not result in negative financial consequences.

Competition

The oil and gas industry is highly competitive, particularly in the following areas:

- searching for and developing new sources of crude oil and natural gas reserves;
- constructing and operating crude oil and natural gas pipelines and facilities; and
- transporting and marketing crude oil, natural gas and other petroleum products.

Our competitors include major integrated oil and gas companies and numerous other independent oil and gas companies. The petroleum industry also competes with other industries in supplying energy, fuel and related products to customers. The pulp and paper chemicals market is also highly competitive. Key success factors are price, product quality, and logistics and reliability of supply.

Competitive forces may result in shortages of prospects to drill, services to carry out exploration, development or operating activities, and infrastructure to produce and transport production. It may also result in an oversupply of crude oil and natural gas. Each of these factors could have a negative impact on costs and prices and, therefore, our financial results.

Operational Risks

Acquiring, developing and exploring for oil and natural gas involves many risks. These include:

- encountering unexpected formations or pressures;
- premature declines of reservoirs;
- blow-outs, well bore collapse, equipment failures and other accidents;
- craterings and sour gas releases;
- uncontrollable flows of oil, natural gas or well fluids; and
- environmental risks.

We operate two facilities that are located in close proximity to populated areas, and each processes materials of potential harm to the local populations. At Balzac, just north of Calgary, we operate a gas plant that processes sour gas. In North Vancouver, we operate a chlor-alkali plant that produces chlorine. We have undertaken several initiatives to mitigate the potential risks associated with these operations. First, we have instituted operating procedures that have allowed each to be verified as Responsible Care® facilities by the Canadian Chemical Producers Association, with our Balzac plant being the first oil and gas facility in the world to be so certified. Also, at North Vancouver, we conducted extensive quantified risk analysis complying with guidelines of the Major Industrial Accidents Council of Canada (MIACC). As a result, substantial changes to operating and inventory practices were implemented. The risk is now consistent with Responsible Care® and MIACC guidelines. Also, at both facilities, we work with surrounding communities to keep them informed of our operations and have invited them to tour our facilities. Finally, we continually work with local municipalities to maintain appropriate emergency response and evacuation plans in the event of an accidental release of chemicals from the facilities.

Although we maintain insurance according to customary industry practice, we may not be fully insured against all of these risks. Losses resulting from the occurrence of these risks may have a material adverse impact on our financial results.

Offshore Operations

Offshore operations are subject to a variety of operating risks peculiar to the marine environment, such as damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. When possible, we take precautionary measures of temporarily shutting-in production, de-manning facilities and ceasing drilling operations. We carry insurance to compensate us for physical damage and business interruption, subject to normal deductions, resulting from such weather conditions.

Our operations in the Gulf of Mexico have been suspended, from time to time, due to hurricanes or tropical storms. While operations are generally restored quickly and production losses are not material, we have a few instances in the last five years where production was suspended for an extended period of time and damage to facilities was incurred. In late August 2005, we shut-in all of our production in the Gulf of Mexico, consisting of approximately 50,000 boe/d before royalties, and ceased drilling operations in anticipation of Hurricane Katrina. Production was restored in early September for most of our fields. On September 20, 2005, we again shut-in all of our production and ceased drilling operations in anticipation of Hurricane Rita. While we incurred minimal damage to most of our facilities, extensive damage was incurred to the third party infrastructure necessary to accommodate our production. As a result, our annualized production was reduced approximately 6,000 boe/d. These storms also resulted in damage to rigs under contract with us, which increased our costs and delayed our drilling schedule. In 2002, our facilities at Eugene Island 295 were damaged during Hurricane Lili. Production from this field was suspended for about four months while temporary production facilities were put in place. During this period, production volumes were reduced by approximately 2,500 boe/d. Production was restored at a reduced rate through temporary facilities for approximately six months while installation of new permanent facilities was completed. It is estimated that volumes were reduced by approximately 1,800 boe/d during this period. In each of these instances, there was no significant financial impact after business interruption and property insurance claims.

Our exploration and development capital programs in our offshore operations are exposed to risk of delay or additional costs by limited access to drilling rigs. Recent industry pressure in the Gulf of Mexico following storm damage sustained in the 2005 hurricane season has reduced the availability of drilling rigs. We have been able to secure contracts for the majority of our 2006 exploration and development drilling in the Gulf of Mexico and the North Sea. In early 2006, we entered into a long-term contract that will give us access to a deep-water drilling rig beginning in 2009 for two years over a three and a half year period, capable of drilling our sub-salt prospects. Our profitability and success at finding replacement reserves may be reduced by extended delays or higher costs of obtaining drilling rigs.

Uncertainty of Reserves Estimates

Our future crude oil and natural gas reserves and production, and therefore our operating cash flows and results of operations, are highly dependent upon our success in exploiting our current reserve base and acquiring or discovering additional reserves. Without reserve additions through exploration, acquisition or development activities, our reserves and production will decline over time as reserves are produced. The business of exploring for, developing or acquiring reserves is capital intensive. To the extent cash flows from operations are insufficient and external sources of capital become limited or unavailable, our ability to make the necessary capital investments to maintain and expand our oil and natural gas reserves will be impaired.

Over the past three years, we experienced net negative revisions of 337 million boe to our proved reserves (including Syncrude and before royalties). This includes 258 million boe of economic revisions related to changes in year-end prices and costs, of which 246 million boe relates to the write-off of the reserves at our Long Lake oil sands project as a result of low bitumen prices. The remaining negative revisions of 79 million boe, representing about 10% of worldwide proved reserves, relate to technical revisions primarily on our producing properties. In Canada, the majority of the negative revisions of 56 million boe occurred in 2003 as a result of an ongoing assessment of the future production profiles of our properties and a reduction of proved undeveloped reserves based on drilling results and updated geologic mapping. In Yemen, the negative revisions of 30 million boe occurred largely in 2003 and 2004 and resulted primarily from lower-than-expected production performance, drilling results and updated geological mapping. In the United States, negative revisions of 21 million boe occurred largely in 2004 and 2005 and resulted primarily from lower-than-expected production performance at our deep water Aspen property and at various properties on the Shelf. These negative revisions were somewhat offset by a positive revision of 17 million boe in our Buzzard field due to updated geologic mapping.

About two-thirds of the 79 million boe of net negative revisions were recognized as proved reserves based on projected future production performance of producing properties. These projections considered historical performance and expected future changes in production using all available engineering and geologic data. However, subsequent production performance did not meet our projections due to such factors as sand production, steeper than expected declines due to higher water cuts and the unexpected loss of well productivity. The remainder of the reserves were recognized as proved undeveloped reserves based on production performance, well control and geologic mapping using seismic and other data. Lower than expected production, greater sweep efficiencies, and unsuccessful drilling caused us to revise our proved reserves estimates downward.

Under SEC rules, we must recognize our oil sands as bitumen reserves rather than the upgraded premium synthetic crude oil that we expect to produce from Long Lake. As a result, we expect price-related revisions, both positive and negative, to occur in the future as the economic producibility of our bitumen and heavy oil reserves are sensitive to year-end prices. In particular, since we recognize our oil sands as bitumen reserves and they are related to one project, all or none of the reserves will likely be considered economic depending on the year-end prices for bitumen, diluent and natural gas, even though the Long Lake project has virtually no exposure to these factors. The impact of year-end prices on our heavy oil reserves is expected to be immaterial.

Heavy Oil Operations

Heavy oil is characterized by high specific gravity or weight and high viscosity or resistance to flow. Because of these features, heavy oil is more difficult and expensive to extract, transport and refine than other types of oil. Heavy oil also yields a lower price relative to light oil and gas, as a smaller percentage of high-value petroleum products can be refined from heavy oil. As a result, our heavy oil operations are exposed to the following risks:

- additional costs may be incurred to purchase diluent to transport heavy oil;
- there could be a shortfall in the supply of diluent which may cause its price to increase; and
- the market for heavy oil is more limited than for light oil making it more susceptible to supply and demand fundamentals which may cause the price to decline.

Any one or combination of these factors could cause some of our heavy oil properties to become uneconomic to produce and/or result in negative reserve revisions.

Additional risk factors relating to our Long Lake oil sands project are provided under “Risk Factors Relating to Long Lake”.

Risk Factors Relating to Long Lake

Our Long Lake project is planned as a fully integrated production, upgrading and co-generation facility. We intend to use Steam Assisted Gravity Drainage (SAGD) technology to recover bitumen from oil sands. As designed, the bitumen will be partially upgraded using the proprietary OrCrude™ process, followed by conventional hydrocracking to produce a sweet, premium synthetic crude oil. The OrCrude™ process also yields liquid asphaltines that will be gasified into a syngas. This syngas will be used as a fuel source for the SAGD process, a source of hydrogen for use in the upgrading process, and to generate electricity through a co-generation facility.

We have a 50% working interest in this project, and our share of the capital costs is estimated to be $1.9 billion ($3.8 billion gross). Given the initial investment and operating costs to produce and upgrade bitumen, the payout period for the project is longer and the economic return is lower than a conventional light oil project with an equal volume of reserves.

Risks associated with our Long Lake oil sands project include the following:

Status of the Long Lake Project

The Long Lake project is currently in the construction stage. There is a risk that actual costs to construct and develop may be higher than expected or that the project may not be completed on time or at all due to many factors, including:

- construction performance falling below expected levels of output or efficiency;
- labour disputes, disruptions or declines in productivity;
- increases in materials or labour costs;
- inability to attract sufficient numbers of qualified workers;
- design errors;
- contractor or operator errors;
- non-performance by third-party contractors;
- changes in project scope;
- delays in obtaining, or conditions imposed by, regulatory approvals;
- breakdown or failure of equipment or processes;
- violation of permit requirements;
- catastrophic events such as fires, earthquakes, storms or explosions; and
- disruption in the supply of energy.

Actual costs to construct and develop the project will vary from our estimates, and such variances may be significant. Our estimate of the cost associated with developing the Long Lake project has been developed with an expected range of accuracy of approximately +/- 15%. In the formative stage of the project, our capital cost estimate was approximately $2.3 billion (gross). After completing further project definition, engineering and reviewing pilot results, we changed the scope of the project to include co-generation facilities, planned for certain redundancies within the upgrader, and applied more conservative estimates to labour productivity. As a result, the capital cost estimate at the time of our Board's sanctioning the project in February 2004 was $3.4 billion (gross). In December 2004, we accelerated the drilling of an additional well pad consisting of 13 well-pairs to ensure certainty and reliability of bitumen production at the commencement of upgrader operations at a cost of $98 million (gross). Recently, we further modified the project design by adding steam generation capacity and soot handling equipment at a cost of $360 million (gross). We expect the other project costs to be within our initial estimates. Our total estimated capital cost is currently $3.8 billion (gross).

SAGD Bitumen Recovery Process

SAGD has been used in Western Canada to increase recoveries from conventional heavy oil reservoirs for over a decade. However, application of SAGD to the insitu recovery of bitumen from oil sands is relatively new. Some of the SAGD oil sands applications to date have been pilot projects, however there are several commercial SAGD projects in steady stage operation.

Our estimates for performance and recoverable volumes for the Long Lake project are based primarily on our three well-pair SAGD pilot and industry performance from SAGD operations in like reservoirs in the McMurray formation in the Athabasca oil sands. Using this data, our assumptions included average well-pair productivity of 900 bbls/d of bitumen and a steam-to-oil ratio of 2.5. In order to test operating parameters, we built a three well-pair SAGD pilot, commenced steaming the reservoir in May 2003 and commenced production in September 2003. The pilot is currently producing at a rate of about 400 barrels of bitumen per day per producing well-pair and an average steam-to-oil ratio of about 4.2. Since September 2003, the pilot has recovered less than 3% of the original bitumen in place. While we expect actual performance to improve as we commence commercial operations where SAGD drilling has confirmed higher quality reservoir conditions, there can be no assurance that our SAGD operation will produce bitumen at the expected levels or steam-to-oil ratio. We have addressed this risk by drilling additional wells and adding steam generating capacity to allow for a steam-to-oil ratio of 3.3, however, if the assumed production rates or steam-to-oil ratio are not achieved, we might have to drill additional wells to maintain optimal production levels, construct additional steam generating capacity and/or purchase natural gas for additional steam generation. These could have a significant adverse impact on the future activities and economic return of the Long Lake project.

Bitumen Upgrading Process

The proprietary OrCrude™ process we are using to upgrade raw bitumen to synthetic crude will be the first commercial application of the process although we have operated it in a 500 bbls/d demonstration plant. All the individual components of the technology used in this process are currently used in commercial applications around the world, however, there can be no assurance that the commercial upgrader being constructed at Long Lake will achieve the same or similar results as the demonstration plant or the results which are forecast. If we are unable to upgrade the bitumen for any reason we may decide to sell it as bitumen without upgrading it, which would expose us to the following risks:

- the market for bitumen is limited;
- additional costs would be incurred to purchase diluent for blending and transporting bitumen;
- there could be a shortfall in the supply of diluent which may cause its price to increase;
- the market price for bitumen is relatively low reflecting its quality differential; and
- additional costs would be incurred to purchase natural gas for use in generating steam for the SAGD process since we would not be producing syngas from the upgrading process.

These factors could have a significant adverse impact on the future activities and economic returns of the Long Lake project.

If any of these factors arise, our operating costs would increase and our revenues would decrease from those we have assumed. This would cause a material decrease in expected earnings from the project and the project may not be profitable under these conditions.

Dependence on OPTI Canada

We are undertaking the Long Lake project jointly with OPTI Canada (OPTI) pursuant to a joint venture agreement governing the construction, ownership and joint operation of the project. The agreement provides for the creation of a management committee that is responsible for the supervision and direction of the management and operation of the project, the supervision and control of the operators and all other matters relating to the development of the project. If our interest in any element of the project falls below 25%, OPTI may be able to make decisions respecting that element without our input, which may adversely affect our operations.

Dependence upon Proprietary Technology

The success of the project and our investment depends to a significant extent on the proprietary technology of OPTI and proprietary technology of third parties that has been, or is required to be, licensed by OPTI. OPTI currently relies on intellectual property rights and other contractual or proprietary rights, including (without limitation) copyright, trademark laws, trade secrets, confidentiality procedures, contractual provisions, licenses and patents, to secure the rights to utilize its proprietary technology and the proprietary technology of third parties. OPTI may have to engage in litigation in order to protect the validity of its patents or other intellectual property rights, or to determine the validity or scope of the patents or proprietary rights of third parties. This kind of litigation can be time-consuming and expensive, regardless of whether or not OPTI is successful. The process of seeking patent protection can itself be long and expensive, and there can be no assurance that any currently pending or future patent applications of OPTI or such third parties will actually result in issued patents, or that, even if patents are issued, they will be of sufficient scope or strength to provide meaningful protection or any commercial advantage to OPTI. Furthermore, others may develop technologies that are similar or superior to the technology of OPTI or such third parties or design around the patents owned by OPTI and/or such third parties. There is also a risk that OPTI may not be able to enter into licensing arrangements with third parties for the additional technologies required for the possible further expansion of the Long Lake upgrader.

Operational Hazards

The operation of the project will be subject to the customary hazards of recovering, transporting and processing hydrocarbons, such as fires, explosions, gaseous leaks, migration of harmful substances, blowouts and oil spills. A casualty occurrence might result in the loss of equipment or life, as well as injury or property damage. We may not carry insurance with respect to all potential casualty occurrences and disruptions. It cannot be assured that our insurance will be sufficient to cover any such casualty occurrences or disruptions. The project could be interrupted by natural disasters or other events beyond our control. Losses and liabilities arising from uninsured or under-insured events could have a material adverse effect on the project and on our business, financial condition and results of operations.

Recovering bitumen from oil sands and upgrading the recovered bitumen into synthetic crude oil and other products involve particular risks and uncertainties. The project is susceptible to loss of production, slowdowns or restrictions on its ability to produce higher value products due to the interdependence of its component systems. Severe climatic conditions can cause reduced production and in some situations result in higher costs. SAGD bitumen recovery facilities and development and expansion of production can entail significant capital outlays. The costs associated with synthetic crude oil production are largely fixed and, as a result, operating costs per unit are largely dependent on levels of production.

The Long Lake SAGD operation and upgrader will process large volumes of hydrocarbons at high pressure and temperatures and will handle large volumes of high-pressure steam. Equipment failures could result in damage to the project's facilities and liability to third parties against which we may not be able to fully insure or may elect not to insure because of high premium costs or for other reasons.

Certain components of the Long Lake project will produce sour gas, which is gas containing hydrogen sulphide. Sour gas is a colourless, corrosive gas that is toxic at relatively low levels to plants and animals, including humans. The project will include integrated facilities for handling and treating the sour gas, including the use of gas sweetening units, sulphur recovery systems and emergency flaring systems. Failures or leaks from these systems or other exposure to sour gas produced as part of the project could result in damage to other equipment, liability to third parties, adverse effect to humans, animals and the environment, or the shut down of operations.

The Long Lake project will produce carbon dioxide emissions. Carbon dioxide is a greenhouse gas that will be regulated by the Kyoto Protocol, which is expected to come into effect in Canada in 2008. We will be required to purchase carbon dioxide credits in connection with these emissions, which we have budgeted at approximately $0.20/bbl of oil produced. If the cost of carbon dioxide credits reaches the Canadian cap, our actual cost would increase to approximately $0.40/bbl of oil produced.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to a substantial portion of Western Canada. Certain aboriginal peoples have filed a claim against the Government of Canada, the Province of Alberta, certain governmental entities and the regional municipality of Wood Buffalo (which includes the city of Fort McMurray, Alberta) claiming, among other things, aboriginal title to large areas of lands surrounding Fort McMurray, including the lands on which the project and most of the other oil sands operations in Alberta are located. Such claims, if successful, could have a significant adverse effect on the project and on us.

Competition

The Canadian and international petroleum industry is highly competitive in all aspects, including the exploration for, and the development of, new sources of supply, the acquisition of oil interests and the distribution and marketing of petroleum products. The Long Lake project competes with other producers of synthetic crude oil blends and other producers of conventional crude oil. Some of the conventional producers have lower operating costs than the project is anticipated to have. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers.

A number of companies other than OPTI and us have announced plans to enter the oil sands business and begin production of synthetic crude oil, or expand existing operations. Expansion of existing operations and development of new projects could materially increase the supply of synthetic crude oil and other competing crude oil products in the marketplace. Depending on the levels of future demand, increased supplies could have a negative impact on prices.

Concentration of Producing Assets

A portion of our production is generated from highly productive individual wells or central production facilities. Examples include:

- central processing facilities, oil pipelines, and export terminal at our two Yemen operations;
- Gunnison SPAR production platform in the Gulf of Mexico;
- highly productive Aspen wells tied-in to a third-party processing facility in the Gulf of Mexico; and
- Scott production platform in the North Sea.

As significant production is generated from each of these assets, any single event causing an interruption to these operations could result in the loss of production. We carry insurance to compensate us for physical damage and business interruption arising from most circumstances but it does not provide for losses arising from equipment failures.

Coal Bed Methane

Coal bed methane (CBM) is commonly referred to as an unconventional form of natural gas because it is primarily stored through adsorption by the coal itself rather than in the pore space of the rock like most conventional gas. The gas is released in response to a drop in pressure in the coal. If the coal is water saturated, water generally needs to be extracted to reduce the pressure and allow gas production to occur. CBM wells typically have lower producing rates and reserves per well than conventional gas wells, although this varies by area. Regulatory approval is required to drill more than one well per section. As a result, the timing of drilling programs and land development can be uncertain.

The Mannville coals in the Fort Assiniboine region of Alberta are deeper than other producing CBM projects and are water saturated. A significant period of time may be required to sufficiently dewater the coals to determine if commercial production is feasible. As a result, we may have to invest significant capital in CBM assets before they achieve commercial rates of production. The wells may never achieve commercial rates of production as there are no commercially proven Mannville CBM projects in operation. We tested the feasibility of gas production from a portion of our Mannville coals and determined that we could achieve commercial production rates with five months of commencing dewatering. Based on these results, we commenced commercial development on our Corbett, Doris and Thunder leases. In the future, we plan to undertake pilots to test the feasibility of gas production before commencing full-scale commercial developments.

CBM projects in some areas of the United States have had negative public reaction due to certain water disposal practices. In Canada, as in the United States, water disposal practices are regulated to ensure public safety and water conservation. Nevertheless, negative public perception around CBM production could impede our access to the resource.

Commitments to Projects Under Development

We have significant commitments in connection with various development activities currently underway. The Syncrude Stage 3 expansion is currently 98% complete and is expected to commence production in mid 2006. Development and construction activities on the Buzzard field are over 88% complete and is expected to commence production in late-2006. Detailed project engineering on our Long Lake SAGD and upgrading project near Fort McMurray, Alberta is substantially complete, SAGD drilling is complete and site construction is well underway. First steam injection is scheduled to begin in late-2006 and the first commercial production of upgraded synthetic crude oil is expected to be achieved in the second half of 2007. We are continuing development of our Upper Mannville CBM assets in the Fort Assiniboine area in 2006. Our combined capital spending for these projects is anticipated to be $1.3 billion in 2006. In these projects, we are exposed to the possibility of cost overruns, which may be significant, and/or delays in commencement of commercial production.

Political Risk

We operate in numerous countries, some of which may be considered politically and economically unstable. Our operations and related assets are subject to the risks of actions by governmental authorities, insurgent groups or terrorists. We conduct our business and financial affairs to protect against political, legal, regulatory and economic risks applicable to operations in the various countries where we operate. However, there can be no assurance that we will be successful in protecting ourselves against these risks and the related financial consequences.

In particular, our operations in Yemen expose us to potential material adverse financial consequences. In 2005, Yemen accounted for $536 million or 46% of our net income and this is expected to decline somewhat in 2006 as production declines on Masila are partially offset by production from completion of development activities on Block 51.

Our Masila operations are important to Yemen, providing 50% of the country's oil production. We are a responsible member of the Yemeni community; we build relationships with its citizens and involve them in key decisions that impact their lives. We also ensure that they benefit from our presence in their country beyond the revenue they receive from the production we operate. Our strong relationship with the people and Government of Yemen has allowed us to operate there without interruptions for over 15 years and we anticipate this continuing.

Our practices have enabled us to operate successfully, not only in Yemen, but also in other parts of the world. We have developed excellent practices to manage the risks successfully.

Environmental Risk

Environmental risks inherent in the oil and gas and chemicals industries are becoming increasingly sensitive as related laws and regulations become more stringent worldwide. Many of these laws and regulations require us to remove or remedy the effect of our activities on the environment at present and former operating sites, including dismantling production facilities and remediating damage caused by the disposal or release of specified substances.

We manage our environmental risks through a comprehensive and sophisticated Safety, Environmental and Social Responsibility (SESR) Management System that meets or exceeds ISO14001 criteria and those of similar management systems. Overall guidance and direction is provided by the SESR Committee of the Board of Directors. In addition, senior management, including the CEO and CFO, regularly meets with SESR management to review and approve SESR policies and procedures, provide strategic direction, review performance and ensure that corrective action is taken when necessary. We develop and implement proactive and preventative measures designed to reduce or eliminate future environmental liabilities, we are prudent and responsible in our management of existing environmental liabilities, and we continuously seek opportunities for performance improvement. We also maintain an ongoing awareness of external trends, demands, commitments, events or uncertainties that may reasonably have a material effect on revenues from continuing operations. These actions provide assurance that we meet or exceed appropriate environmental standards worldwide.

- At December 31, 2005, $611 million ($1,471 million, undiscounted) has been provided in the Consolidated Financial Statements for future asset retirement costs, relating to our oil and gas, Syncrude and chemicals facilities. Our provision for future retirement costs does not include costs related to the Syncrude upgrader or sulphur pile as we are currently unable to reasonably determine the fair value of these obligations.
- During 2005, we increased our asset retirement obligations by $210 million (2004—$170 million) to reflect new obligations incurred or acquired, general industry cost pressures and more stringent environmental laws and regulations.
- Actual site remediation expenditures for the year were $34 million (2004—$31 million). We anticipate actual site remediation expenditures in 2006 to approximate $21 million.
- We perform periodic internal and external assessments of our operations and adjust our estimates and retirement obligations accordingly.
- During 2002, we conducted an external audit of our management systems for safety, environment and social responsibility issues. Overall, the review was positive and the few minor recommendations for improvement were implemented.
- During 2003 and 2004, we conducted an external operational audit and confirmed that our management systems for safety, environment and social responsibility issues were being followed.

Climate Change

The Kyoto Protocol came into force on February 16, 2005. Canada ratified the Kyoto Protocol in December 2002. In 1997, Canada committed to an emission reduction of 6% below 1990 levels during the First Commitment period (2008 to 2012). On March 24, 2005, the Canadian government introduced to Parliament for first reading Bill C-43 "An Act to Implement Certain Provisions of the Budget Tabled by Parliament on February 23, 2005" (Bill C-43), which contained certain proposals relating to the Kyoto Protocol. While the content of Bill C-43 and whether it will eventually pass into law is uncertain, it constitutes the first attempt by the Canadian government to implement obligations under the Kyoto Protocol. As well, on April 13, 2005, Environment Canada released its Kyoto Plan, which sets out a number of initiatives, including the lowering of the target for reductions in greenhouse gas emissions by large final emitters from the initial target of 55 megatons to a new target of 45 megatons. Any required reductions in the greenhouse gases emitted from our operations could result in increases in our capital expenditures and operating expenses, especially those related to the Long Lake project, which could have an adverse effect on our results of operations and financial condition. Recent changes in the Canadian government may have an impact on our future obligations under the Kyoto Plan.

CRITICAL ACCOUNTING ESTIMATES

We make estimates and assumptions that affect the reported amounts of our assets and liabilities and the disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements and our revenues and expenses during the reporting period. Our management reviews these estimates, including those related to accruals, litigation, environmental and asset retirement obligations, income taxes and the determination of proved reserves on an ongoing basis. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates. Our critical accounting estimates are discussed below.

Oil and Gas Accounting—Reserves Determination

We follow the successful efforts method of accounting for our oil and gas activities, as described in Note 1 to our Consolidated Financial Statements. Successful efforts accounting depends on the estimated reserves we believe are recoverable from our oil and gas properties.

The process of estimating reserves is complex. It requires significant judgements and decisions based on available geological, geophysical, engineering and economic data.

To estimate the economically recoverable oil and natural gas reserves and related future net cash flows, we incorporate many factors and assumptions including:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future oil and gas prices and quality differentials;
- assumed effects of regulation by governmental agencies; and
- future development and operating costs.

We believe these factors and assumptions are reasonable based on the information available to us at the time we prepare our estimates. However, these estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change.

Management is responsible for estimating the quantities of proved oil and natural gas reserves and for preparing related disclosures. Estimates and related disclosures are prepared in accordance with SEC requirements, generally accepted industry practices in the US as promulgated by the Society of Petroleum Engineers, and the standards of the Canadian Oil and Gas Evaluation Handbook modified to reflect SEC requirements.

Reserve estimates for each property are internally prepared at least annually by the property's reservoir engineer. They are reviewed by engineers familiar with the property and by divisional management. An Executive Reserves Committee, including our CEO, CFO and Board-appointed internal qualified reserves evaluator, meet with divisional reserves personnel to review the estimates and any changes from previous estimates.

The internal qualified reserves evaluator assesses whether our reserves estimates and the Standardized Measure of Discounted Future Net Cash Flows and Changes Therein, included in the Supplementary Financial Information, have been prepared in accordance with our reserve standards. His opinion stating that the reserves information has, in all material respects, been prepared according to our reserves standards is included in an exhibit to this Form 10-K.

We also have at least 80% of our reserves assessed annually by independent qualified reserves consultants. Given that the respective reserves estimates are based on numerous assumptions and interpretations, differences in estimates prepared by us and an independent reserves consultant are resolved when the differences are greater than 10%.

The Board of Directors has established a Reserves Review Committee (Reserves Committee) to assist the Board and the Audit and Conduct Review Committee to oversee the annual review of our oil and gas reserves and related disclosures. The Reserves Committee is comprised of three or more directors, the majority of whom are independent, and each being familiar with estimating oil and gas reserves. The Reserves Committee meets with management periodically to review the reserves process, results and related disclosures. The Reserves Committee appoints and meets with each of the internal qualified reserves evaluator and independent reserves consultants independent of management to review the scope of their work, whether they have had access to sufficient information, the nature and satisfactory resolution of any material differences of opinion, and in the case of the independent reserves consultants, their independence.

The Reserves Committee has reviewed Nexen's procedures for preparing the reserves estimates and related disclosures. It has

reviewed the information with management, and met with the internal qualified reserves evaluator and the independent qualified reserves consultants. As a result of this, the Reserves Committee is satisfied that the internally-estimated reserves are reliable and free of material misstatement. Based on the recommendation of the Reserves Committee, the Board has approved the reserves estimates and related disclosures in the Form 10-K.

Reserves estimates are critical to many of our accounting estimates, including:

- Determining whether or not an exploratory well has found economically producible reserves. If successful, we capitalize the costs of the well, and if not, we expense the costs immediately. In 2005, $143 million of our total $456 million spent on exploration drilling was expensed. If none of our drilling had been successful, our net income would have decreased by $206 million after tax.
- Calculating our unit-of-production depletion rates. Both proved and proved developed reserves[1] estimates are used to determine rates that are applied to each unit-of-production in calculating our depletion expense. Proved reserves are used where a property is acquired and proved developed reserves are used where a property is drilled and developed. In 2005, oil and gas and Syncrude depletion of $628 million was recorded in depletion, depreciation, amortization and impairment expense. If our reserves estimates changed by 10%, our depletion, depreciation, amortization and impairment expense would have changed by approximately $42 million, after tax, assuming no other changes to our reserves profiles.
- Assessing, when necessary, our oil and gas assets for impairment. Estimated future undiscounted cash flows are determined using proved reserves. The critical estimates used to assess impairment, including the impact of changes in reserves estimates, are discussed below.

Since we do not have any loan covenants directly linked to reserves, it would take a significant decrease in our proved reserves to limit our ability to borrow money under our term credit facilities, as previously described in the Liquidity section of the MD&A.

Oil and Gas Accounting—Impairment

We evaluate our oil and gas properties for impairment if an adverse event or change occurs. Among other things, this might include falling oil and gas prices, a significant revision to our reserves estimates, changes in operating costs, or significant or adverse political changes. If one of these occurs, we assess estimated undiscounted future cash flows for affected properties to determine if they are impaired. If the undiscounted future cash flows for a property are less than the carrying amount of that property, we calculate its fair value using a discounted cash flow approach. The property is then written down to its fair value.

We assessed our oil and gas properties for impairment at the end of 2005 and found no impairments were required based on our assumptions.

Cash flow estimates for our impairment assessments require assumptions about two primary elements—future prices and reserves.

Our estimates of future prices require significant judgements about highly uncertain future events. Historically, oil and gas prices have exhibited significant volatility—over the last five years, prices for WTI and NYMEX gas have ranged from US$17/bbl to US$71/bbl and US$2/mmbtu to US$19/mmbtu, respectively. Our forecasts for oil and gas revenues are based on prices derived from a consensus of future price forecasts amongst industry analysts and our own assessments. Our estimates of future cash flows generally assume our long-term price forecast and forecast operating and development costs. Given the significant assumptions required and the possibility that actual conditions will differ, we consider the assessment of impairment to be a critical accounting estimate. A change in this estimate would impact all except our chemicals business.

If forecast WTI crude oil prices were to fall to mid-US$20/bbl levels our initial assessment of impairment indicators would not change. Although oil and gas prices fluctuate a great deal in the short-term, they are typically stable over a longer-time horizon. This mitigates the potential for impairment.

Any impairment charges would lower our net income.

It is difficult to determine and assess the impact of a decrease in our proved reserves on our impairment tests. The relationship between the reserves estimate and the estimated undiscounted cash flows, and the nature of the property-by-property impairment test, is complex. As a result, we are unable to provide a reasonable sensitivity analysis of the impact that a reserves estimate decrease would have on our assessment of impairment.

1 "Proved" oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and natural gas liquids that geological and engineering data demonstrate with reasonable certainty can be recoverable in future years from known reservoirs under existing economic and operating conditions. Reservoirs are considered "proved" if economic producibility is supported by either actual production or a conclusive formation test. "Proved developed" oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operation methods.

Asset Retirement Obligations

We are required to remove or remedy the effect of our activities on the environment at our present and former operating sites by dismantling and removing production facilities and remediating any damage caused. Estimating our future asset retirement obligations requires us to make estimates and judgments with respect to activities that will occur many years into the future. In addition, the ultimate financial impact of environmental laws and regulations is not always clearly known and cannot be reasonably estimated as standards evolve in the countries in which we operate.

We record asset retirement obligations in our consolidated financial statements by discounting the present value of the estimated retirement obligations associated with our oil and gas wells and facilities and chemical plants. In arriving at amounts recorded, numerous assumptions and judgments are made with respect to ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and expected changes in legal, regulatory, environmental and political environments. The asset retirement obligations we have recorded result in an increase to the carrying cost of our property, plant and equipment. The obligations are accreted with the passage of time. A change in any one of our assumptions could impact our asset retirement obligations, our property, plant and equipment and our net income.

It is difficult to determine the impact of a change in any one of our assumptions. As a result, we are unable to provide a reasonable sensitivity analysis of the impact a change in our assumptions would have on our financial results. We are confident, however, that our assumptions are reasonable.

Business Combination—Purchase Price Allocation

During the fourth quarter of 2004, we acquired a company operating and exploring oil and gas properties located in the North Sea. We accounted for this acquisition using the purchase method of accounting. Under this method, we were required to record on our consolidated balance sheet the estimated fair values of the acquired company's assets and liabilities at the acquisition date. The excess of the purchase price over the fair values of the tangible and intangible net assets acquired was recorded as goodwill.

We have made various assumptions in determining the fair values of the acquired company's assets and liabilities. The most significant assumptions and judgments made relate to the estimation of the fair value of the oil and gas properties. To determine the fair value of these properties, we estimated (a) oil and gas reserves in accordance with our reserve standards, and (b) future prices of oil and gas.

Our reserve estimates were based on the work performed by our engineers and outside consultants. The judgments associated with these estimated reserves are described earlier in our critical accounting estimates discussion entitled "Oil and Gas Accounting—Reserves Determination". Our estimates of future prices were based on prices derived from a consensus of future price forecasts amongst industry analysts and our own assessments. The judgments associated with these estimates are described earlier in our critical accounting estimates discussion entitled "Oil and Gas Accounting—Impairment".

We applied our estimated future prices to the estimated reserves quantities acquired, and we estimated future operating and development costs, to arrive at estimated future net revenues for the properties acquired. For proved properties, we discounted the future net revenues using after-tax discount rates. The same principles were applied in arriving at the fair value of unproved properties acquired. These unproved properties generally represent the value of the probable and possible reserves. Because of their very nature, probable and possible reserve estimates are more imprecise than those of proved reserves. To compensate for the inherent risk of estimating and valuing unproved reserves, an appropriate risk-weighting factor was applied to the discounted future net revenues of the probable and possible reserves in each particular instance.

If the fair value allocated to oil and gas properties acquired had been decreased by $50 million, future income tax liabilities would have decreased by $20 million and goodwill would have increased by $30 million.

Future Income Taxes

We follow the liability method of accounting for income taxes whereby future income tax assets and liabilities are recognized based on temporary differences in reported amounts for financial statement and tax purposes. We carry on business in several countries and as a result, we are subject to income taxes in numerous jurisdictions. The determination of our income tax provision is inherently complex and we are required to interpret continually changing regulations and make certain judgments. While income tax filings are subject to audits and reassessments, we believe we have made adequate provision for all income tax obligations. However, changes in facts and circumstances as a result of income tax audits, reassessments, jurisprudence and any new legislation may result in an increase or decrease in our provision for income taxes.

NEW ACCOUNTING PRONOUNCEMENTS

Canadian Pronouncements

In an effort to harmonize Canadian GAAP with US GAAP, the Canadian Accounting Standards Board (AcSB) has issued sections:

- 1530, *Comprehensive Income;*
- 3855, *Financial Instruments—Recognition and Measurement;* and
- 3865, *Hedges.*

Under these new standards, all financial assets should be measured at fair value with the exception of loans, receivables and investments that are intended to be held to maturity and certain equity investments, which should be measured at cost. Similarly, all financial liabilities should be measured at fair value when they are held for trading or they are derivatives.

Gains and losses on financial instruments measured at fair value will be recognized in the income statement in the periods they arise with the exception of gains and losses arising from:

- financial assets held for sale, for which unrealized gains and losses are deferred in other comprehensive income until sold or impaired; and
- certain financial instruments that qualify for hedge accounting.

Sections 3855 and 3865 make use of "other comprehensive income". Other comprehensive income comprises revenues, expenses, gains and losses that are recognized in comprehensive income, but are excluded from net income. Unrealized gains and losses on qualifying hedging instruments, translation of self-sustaining foreign operations, and unrealized gains or losses on financial instruments held for sale will be included in other comprehensive income and reclassified to net income when realized. Comprehensive income and its components will be a required disclosure under the new standard.

These new standards are effective for fiscal years beginning on or after October 1, 2006 and early adoption is permitted. Adoption of these standards as at December 31, 2005 would have the following impact on our Consolidated Financial Statements:

(Cdn$ millions)	Increase/ (Decrease)
Accounts Payable	35
Future Income Tax Liabilities	(11)
Shareholders' Equity	(24)

In June 2005, the AcSB issued Section 3831, *Non-Monetary Transactions*, which replaces Section 3830 and requires all non-monetary transactions to be measured at fair value unless:

- the transaction lacks commercial substance;
- the transaction is an exchange of a product or property held for sale in the ordinary course of business for a product or property to be sold in the same line of business to facilitate sales to customers other than the parties to the exchange;
- neither the fair value of the assets or services received nor the fair value of the assets or services given up is reliably measurable; or
- the transaction is a non-monetary, non-reciprocal transfer to owners that represents a spin-off or other form of restructuring or liquidation.

The new requirements apply to non-monetary transactions initiated in periods beginning on or after January 1, 2006. Earlier adoption is permitted as of the beginning of a period beginning on or after July 1, 2005. We do not expect the adoption of this section will have any material impact on our results of operations or financial position.

In December 2005, the CICA's Emerging Issues Committee issued Abstract 159, *Conditional Asset Retirement Obligations* (EIC-159). EIC-159 clarifies that the term conditional asset retirement obligation, as used in CICA Handbook Section 3110, *Asset Retirement Obligations* refers to a legal obligation to perform an asset retirement activity where the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. EIC-159 also clarifies when there would be sufficient information to reasonably estimate the fair value of an asset retirement obligation. EIC-159 is effective for interim and annual reporting periods ending after March 31, 2006. We do not expect the adoption of this section will have any material impact on our results of operations or financial position.

US PRONOUNCEMENTS

In November 2004, the Financial Accounting Standards Board (FASB) issued Statement 151, *Inventory Costs*. This statement amends ARB 43 to clarify that:

- abnormal amounts of idle facility expense, freight, handling costs and wasted material (spoilage) should be recognized as current-period charges; and
- requires the allocation of fixed production overhead to inventory based on the normal capacity of the production facilities.

The provisions of this statement are effective for inventory costs incurred during fiscal years beginning after June 15, 2005. We do not expect the adoption of this statement will have any material impact on our results of operations or financial position.

In December 2004, the FASB issued Statement 123(R), *Share-Based Payments*. This statement revises Statement 123, *Accounting for Stock-Based Compensation*, and supersedes APB Opinion 25, *Accounting for Stock Issued to Employees*. Statement 123(R) requires all stock-based awards issued to employees to be measured at fair-value and to be expensed in the income statement. This statement is effective for fiscal years beginning after June 15, 2005.

We are currently expensing stock-based awards issued to employees using the fair-value method for equity-based awards and the intrinsic method for liability-based awards. Adoption of this standard will change our expense under US GAAP for tandem options and stock appreciation rights as these awards will be measured using the fair-value method rather than the intrinsic method. Upon implementing the new rules, we expect to record an expense for US GAAP purposes of $3 million ($2 million net of income taxes) in 2006, reflecting the cumulative effect of the change in accounting policy.

In December 2004, the FASB issued Statement 153, *Exchanges of Nonmonetary Assets*, an amendment of APB Opinion 29, *Accounting for Nonmonetary Transactions*. This amendment eliminates the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. Under Statement 153, if a nonmonetary exchange of similar productive assets meets a commercial-substance test and fair value is determinable, the transaction must be accounted for at fair value resulting in the recognition of any gain or loss. This statement is effective for nonmonetary transactions in fiscal periods that begin after June 15, 2005. We do not expect the adoption of this statement will have any material impact on our results of operations or financial position.

In March 2005, the FASB issued Financial Interpretation 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47). FIN 47 clarifies that the term conditional asset retirement obligation as used in FASB Statement No. 143, *Accounting for Asset Retirement Obligations*, refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement. Thus, the timing and (or) method of settlement may be conditional on a future event. Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. FIN 47 is effective no later than the end of fiscal years ending after December 15, 2005. The adoption of this statement has not had a material impact on our results of operations or financial position.

In March 2005, the Emerging Issues Task Force (EITF) reached a consensus on Issue No. 04-6, *Accounting for Stripping Costs Incurred during Production in the Mining Industry*. In the mining industry, companies may be required to remove overburden and other mine waste materials to access mineral deposits. The EITF concluded that the costs of removing overburden and waste materials, often referred to as "stripping costs", incurred during the production phase of a mine are variable production costs that should be included in the costs of the inventory produced during the period that the stripping costs are incurred. Issue No. 04-6 is effective for the first reporting period in fiscal years beginning after December 15, 2005, with early adoption permitted. We do not expect the adoption of this statement will have a material impact on our results of operations or financial position.

In June 2005, the FASB issued Statement 154, *Accounting Changes and Error Corrections*, which replaces APB Opinion 20 and FASB Statement 3. Statement 154 changes the requirements for the accounting and reporting of a change in accounting principle. Opinion 20 previously required that most voluntary changes in accounting principles be recognized by including the cumulative effect of the new accounting principle in net income of the period of the change. In the absence of explicit transition provisions provided for in new or existing accounting pronouncements, Statement 154 now requires retrospective application of changes in accounting principle to prior period financial statements, unless it is impracticable to do so. The Statement is effective for fiscal years beginning after December 15, 2005. We do not expect the adoption of this statement will have a material impact on our results of operations or financial position.

In September 2005, the EITF reached a consensus on Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*. This issue addresses the question of when it is appropriate to measure purchase and sales of inventory at fair value and record them in cost of sales and revenues and when they should be recorded as exchanges measured at the book value of the item sold. The EITF concluded that purchases and sales of inventory with the same counterparty that are entered into in contemplation of one another should be combined and recorded as exchanges measured at the book value of the item sold. The consensus should be applied to new arrangements entered into and modifications or renewals of existing agreements, beginning with the second quarter of 2006. We do not expect the adoption of this statement will have a material impact on our results of operations or financial position.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to normal market risks inherent in the oil and gas and chemicals business, including commodity price risk, foreign-currency rate risk, interest rate risk and credit risk. We recognize these risks and manage our operations to minimize our exposures to the extent practical.

NON-TRADING

Commodity Price Risk

Commodity price risk related to conventional and synthetic crude oil prices is our most significant market risk exposure. Crude oil and natural gas are commodities which are sensitive to numerous worldwide factors, many of which are beyond our control, and are generally sold at contract or posted prices. Changes in world crude oil and natural gas prices may significantly affect our results of operations and cash generated from operating activities. Consequently, such prices also may affect the value of our oil and gas properties and our level of spending for oil and gas exploration and development.

Our crude oil prices are based on various reference prices, primarily the WTI crude oil reference price and other prices which generally track the movement in WTI. Adjustments are made to the reference prices to reflect quality differentials and transportation. WTI and other international reference prices are affected by numerous and complex worldwide factors such as supply and demand fundamentals, economic outlooks, production quotas set by the Organization of Petroleum Exporting Countries and political events. Quality differentials are affected by local supply and demand factors.

To a lesser extent we are also exposed to natural gas price movements. Natural gas prices are generally influenced by oil prices and North American supply and demand, and to a lesser extent local market conditions.

In 2005, WTI averaged US$56.58/bbl reaching a high of US$70.85/bbl and a low of US$41.25/bbl. NYMEX natural gas prices averaged US$8.99/mmbtu in 2005, reaching a high of US$15.78/mmbtu and a low of US$5.71/mmbtu.

Our sensitivities to commodity prices and the expected impact on our 2006 cash flow from operating activities and net income are as follows:

(Cdn$ millions)	Cash Flow	Net Income
WTI—US$1 Change	40	32
NYMEX Natural Gas—US$0.10 Change	7	6

These sensitivities to changes in benchmark prices for crude oil and natural gas are based on our estimated 2006 production levels for crude oil and natural gas and assume a Canadian/US dollar exchange rate of 85¢. Our estimated crude oil and natural gas production range for 2006 is between 220,000 and 240,000 boe/d before royalties, of which natural gas represents approximately 20%.

The majority of our oil and gas production is sold under short-term contracts, exposing us to short-term price movements. Other energy contracts we enter into also expose us to commodity price risk between the time we purchase and sell contracted volumes. From time to time, we actively manage these risks by using commodity futures, forwards, swaps and options.

In 2004, we purchased WTI put options to manage the commodity price risk exposure on a portion of our oil production in 2005 and 2006. In 2006, these options establish an annual average WTI floor price of US$38/bbl on 60,000 bbls/d of production.

Foreign Currency Risk

A substantial portion of our activities are transacted in or referenced to US dollars including:

- sales of crude oil, natural gas and certain chemicals products;
- capital spending and expenses for our oil and gas and chemicals operations; and
- short-term and long-term borrowings.

The Canadian/US dollar exchange rate averaged 0.8253¢ in 2005 with a high of 0.8690¢ and a low of 0.7872¢.

Our sensitivities to the US dollar and the expected impact of a one cent change on our 2006 cash flow from operating activities, net income, capital expenditures and long-term debt are as follows:

(Cdn$ millions)	Cash Flow	Net Income	Capital Expenditures	Long-Term Debt
$0.01 Change in US to Canadian Dollar	25	12	18	38

Our sensitivities to changes in the Canadian/US dollar exchange rate are calculated based on projected revenues, expenses, capital expenditures and US-dollar denominated long-term debt for 2006. These estimates are based on a WTI price for crude oil of US$55.00/bbl, a NYMEX natural gas price of US$9.25/mcf and a Canadian/US dollar exchange rate of 85¢.

We manage our exposure to fluctuations between the US and Canadian dollar by matching our expected net cash flows and borrowings in the same currency. Net revenue from our foreign operations and our US-dollar borrowings are generally used to fund US-dollar capital expenditures and debt repayments. Since the timing of cash inflows and outflows is not necessarily interrelated, particularly for capital expenditures, we maintain revolving Canadian and US-dollar borrowing facilities that can be used or repaid depending on expected net cash flows. We designate our US-dollar borrowings as a hedge against our US-dollar net investment in foreign operations.

Our Buzzard project in the North Sea creates foreign currency exposure as a portion of the capital costs are denominated in British pounds (GBP) and Euros. In order to reduce our exposure to fluctuations in these currencies relative to the US dollar, we purchased foreign currency call options in early 2005. These options set a ceiling on most of our British pound and Euro spending exposure from February 2005 through to the end of 2006.

These call options effectively set a maximum GBP-US$ exchange rate of 1.95 on a total of GBP 84 million for the period March 2005 through June 2005, and a maximum rate of 2.00 on a total of GBP 185 million for the period July 2005 through December 2006. With respect to our Euro exposure, the call options effectively set a maximum Euro-US$ exchange rate of 1.40 on a total of Euros 59 million for the period February through September 2005. Managing our exchange rate exposure through the use of call options caps our exposure if the US dollar weakens relative to the British pound and the Euro but allows us to benefit fully from any strengthening of the US dollar relative to these currencies.

Our chemicals operations are exposed to changes in the US-dollar exchange rate as a portion of their sales are denominated in US-dollars. In connection with the Canexus initial public offering, we purchased US-dollar call options to reduce this exposure. These call options give Canexus the right to sell US$11 million monthly and purchase Canadian dollars at an exchange rate of US$0.813 until August 2006.

We do not have any material exposure to highly inflationary foreign currencies.

We occasionally use derivative instruments to effectively convert cash flows from Canadian to US dollars and vice versa. At December 31, 2005, we held a foreign currency derivative instrument that obligates us and the counterparty to exchange principal and interest amounts. In November 2006, we will pay US$37 million and receive Cdn $50 million.

Interest Risk

We are exposed to fluctuations in short-term interest rates from our floating-rate debt and, to a lesser extent, our derivative instruments and long-term debt, as their market value is sensitive to interest rate fluctuations. To minimize our exposure to interest rate fluctuations, we occasionally use derivative instruments.

Short-term interest rates for US-dollar borrowings averaged 4.1% in 2005, reaching a high of 4.8% and low of 3.5%.

Our sensitivity to interest rates and the expected impact of a 1% change in interest rates on our 2006 cash flow from operating activities and net income is as follows:

(Cdn$ millions)	Cash Flow	Net Income
Interest Rates—1% change in rates	4	3

Our sensitivity to changes in interest rates is based on 2006 estimated average floating rate debt of $380 million and a Canadian/US dollar exchange rate of 85¢.

Our floating rate debt exposes us to changes in interest payments as interest rates fluctuate. To manage this exposure, we maintain a combination of fixed and floating rate borrowings and facilities. At December 31, 2005 fixed-rate borrowings comprised 95% (2004—56%) of our long-term debt at an effective average rate of 6.3% (2004—6.6%). During the year we periodically drew on our unsecured syndicated term credit facilities and at December 31, 2005, floating rate debt comprised 5% (2004—44%) of our long-term debt at an effective average rate of 4.4% (2004—3.2%).

We had no interest rate swaps outstanding in 2005 or 2004.

TRADING

Commodity Price Risk

Our marketing operation is involved in the marketing and trading of crude oil, natural gas, natural gas liquids and power through the use of physical purchase and sales contracts as well as financial commodity contracts. These activities expose us to commodity price risk. The marketing operation actively manages this risk by utilizing energy-related futures, forwards, swaps and options, and generally attempts to balance its physical and financial contracts in terms of contract volumes and timing of performance and delivery obligations. However, net open positions may exist or may be established to take advantage of existing market conditions.

Open positions exist where not all contracted purchases and sales have been matched. These net open positions allow us to generate income, but also expose us to risk of loss due to fluctuating market prices (market risk). Open positions and derivative instruments expose us to other risks, including credit risk and the risk of margin calls from third parties. The inability to close out options, futures and forward positions could have an adverse impact on the use of derivative instruments to effectively hedge our portfolio and/or generate income from marketing activities. We control the level of market risk through daily monitoring of our energy-trading portfolio relative to:

- prescribed limits for Value-at-Risk (VaR);
- nominal size of commodity positions;
- stop loss limits; and
- stress testing.

VaR is a statistical estimate that is reliable when normal market conditions prevail. Our VaR calculation estimates the maximum probable loss given a 95% confidence level that we would incur if we were to unwind our outstanding positions over a two-day period. We estimate VaR using the Variance-Covariance method based on historical commodity price volatility and correlation inputs. Our estimate is based upon the following key assumptions:

- changes in commodity prices are normally distributed;
- price volatility remains stable; and
- price correlation relationships remain stable.

If a severe market shock occurred, the key assumptions underlying our VaR estimate could be exceeded and the potential loss could be greater than our estimate. There were no changes in the methodology we used to estimate VaR in 2005. However, based on our assessment of risk measurements, we have removed VaR relating to credit from our total VaR and we review this separately. For 2005, VaR relating to credit ranged between $3 million and $5 million.

Stress testing complements our VaR estimate. It is used to ensure that we are not exposed to large losses, not captured by VaR, which might result from infrequent but extreme market conditions.

Our year-end, annual high, annual low and annual average VaR amounts are as follows:

(Cdn$ millions)	2005	2004	2003
Value-at-Risk			
Year End	24	21	21
High	28	42	31
Low	11	17	14
Average	21	29	20

Our Board of Directors has approved formal risk management policies for our energy trading activities. Market and credit risks are monitored daily by a risk group that operates independently and ensures compliance with our risk management policies. The Finance Committee of the Board of Directors and our Risk Management Committee monitor our exposure to the above risks and review the results of our energy trading activities regularly.

CREDIT RISK

Credit risk affects both our trading and non-trading activities and is the risk of loss if counterparties do not fulfill their contractual obligations. Most of our credit exposures are with counterparties in the oil and gas and energy trading industry and are subject to normal industry credit risk. We take the following measures to reduce this risk:

- we assess the financial strength of our counterparties through a rigorous credit process;
- we limit the total exposure extended to individual counterparties, and may require collateral from some counterparties;
- we routinely monitor credit risk exposures, including sector, geographic and corporate concentrations of credit, and report these to our Risk Management Committee and the Finance Committee of the Board;
- we set credit limits based on rating agency credit ratings and internal assessments based on company and industry analysis;
- we review counterparty credit limits regularly; and
- we use standard agreements that allow for the netting of exposures associated with a single counterparty.

We believe these measures minimize our overall credit risk. However, there can be no assurance that these processes will protect us against all losses from non-performance. At December 31, 2005:

- over 97% of our credit exposures were investment grade; and
- only two counterparties individually made up more than 5% of our credit exposure. Both were investment grade.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this report, including those appearing in *Items 1 and 2—Business and Properties* and *Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations*, are forward-looking statements[1]. Forward-looking statements are generally identifiable by terms such as *anticipate, believe, intend, plan, expect, estimate, budget, outlook* or other similar words, and include statements relating to future production associated with our Coal Bed Methane, Long Lake, Syncrude, North Sea and West Africa projects and future capital investment plans.

These statements are subject to known and unknown risks and uncertainties and other factors which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. These risks, uncertainties and other factors include, among others:

- market prices for oil, natural gas and chemicals products;
- our ability to explore, develop, produce and transport crude oil and natural gas to markets;
- the results of exploration and development drilling and related activities;
- foreign-currency exchange rates;
- economic conditions in the countries and regions in which we carry on business;
- governmental actions that increase taxes, change environmental and other laws and regulations;
- renegotiations of contracts; and
- political uncertainty, including actions by insurgent or other armed groups or other conflict, including conflict between states.

The above items and their possible impact are discussed more fully in the section, titled *Business Risk Management* in Item 7 and *Quantitative and Qualitative Disclosures about Market Risk in Item 7A*.

The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and management's future course of action depends upon our assessment of all information available at that time. Any statements regarding the following are forward-looking statements:

- future crude oil, natural gas or chemicals prices;
- future production levels;
- future cost recovery oil revenues from our operations in Yemen;
- future capital expenditures and their allocation to exploration and development activities;
- future asset dispositions;
- future sources of funding for our capital program;
- possible commerciality, development plans or capacity expansions;
- future ability to execute dispositions of assets or businesses;
- future debt levels;
- future cash flows and their uses;
- future drilling of new wells;
- ultimate recoverability of reserves;
- expected finding and development costs;
- expected operating costs;
- future demand for chemicals products;
- future expenditures and future allowances relating to environmental matters; and
- dates by which certain areas will be developed or will come on stream.

We believe that any forward-looking statements made are reasonable based on information available to us on the date such statements were made. However, no assurance can be given as to future results, levels of activity and achievements. Except to the extent required by law, we undertake no obligation to update publicly or revise any forward-looking statements contained in this report. All subsequent forward-looking statements, whether written or oral, attributable to us or persons acting on our behalf are expressly qualified in their entirety by these cautionary statements.

1 Within the meaning of the United States *Private Securities Litigation Reform Act of 1995*, Section 21E of the United States *Securities Exchange Act of 1934*, as amended, and Section 27A of the United States *Securities Act of 1933*, as amended.

SPECIAL NOTE TO CANADIAN INVESTORS

Nexen is an SEC registrant and a Form 10-K and related forms filer. Therefore, our reserves estimates and securities regulatory disclosures follow SEC requirements. In 2003, Canadian regulatory authorities adopted *National Instrument 51-101—Standards of Disclosure for Oil and Gas Activities* (NI 51-101) which prescribes that Canadian companies follow certain standards for the preparation and disclosure of reserves and related information. We have been granted the following exemptions permitting us to:

- substitute our SEC disclosures for much of the annual disclosure required by NI 51-101;
- prepare our reserves estimates and related disclosures in accordance with SEC requirements, generally accepted industry practices in the US as promulgated by the Society of Petroleum Engineers, and the standards of the *Canadian Oil and Gas Evaluation Handbook* (COGE Handbook) modified to reflect SEC requirements;
- dispense with the requirement to have our reserves estimates and the *Standardized Measure of Discounted Future Net Cash Flows and Changes Therein*, included in the Supplementary Financial Information, evaluated or audited by independent qualified reserves evaluators; and
- not disclose certain prescribed information pertaining to prospects if such disclosures would result in the contravention of a legal obligation, would likely be detrimental to our competitive interests or the information does not exist.

As a result of these exemptions, Canadian investors should note the following fundamental differences in reserves estimates and related disclosures contained in the Form 10-K:

- SEC registrants apply SEC reserves definitions and prepare their reserves estimates in accordance with SEC requirements and generally accepted industry practices in the US whereas NI 51-101 requires adherence to the definitions and standards promulgated by the COGE Handbook;
- the SEC mandates disclosure of proved reserves and the *Standardized Measure of Discounted Future Net Cash Flows and Changes Therein* calculated using year-end constant prices and costs only whereas NI 51-101 also requires disclosure of reserves and related future net revenues using forecast prices;
- the SEC mandates disclosure of proved and proved developed reserves by geographic region only whereas NI 51-101 requires disclosure of more reserve categories and product types;
- the SEC does not require separate disclosure of proved undeveloped reserves or related future development costs whereas NI 51-101 requires more information regarding proved undeveloped reserves, related development plans and future development costs;
- the SEC does not require disclosure of finding and development (F&D) costs per boe of proved reserves additions whereas NI 51-101 requires that various F&D costs per boe be disclosed. NI 51-101 requires that F&D costs be calculated by dividing the aggregate of exploration and development costs incurred in the current year and the change in estimated future development costs relating to proved reserves by the additions to proved reserves in the current year. However, this will generally not reflect full cycle finding and development costs related to reserve additions for the year;
- the SEC leaves the engagement of independent qualified reserves evaluators to the discretion of a company's board of directors whereas NI 51-101 requires issuers to engage such evaluators and to file their reports;
- the SEC does not consider the upgrading component of our integrated oil sands project at Long Lake as an oil and gas activity, and therefore permits recognition of bitumen reserves only. NI 51-101 specifically includes such activity as an oil and gas activity and recognizes synthetic oil as a product type, and therefore permits recognition of synthetic reserves. Given high natural gas prices and wide light/heavy differentials at year end, we have not recognized any proved bitumen reserves under SEC requirements whereas under NI 51-101 we would have recognized 200 million barrels of proved synthetic reserves (before royalties); and
- the SEC considers our Syncrude operation as a mining activity rather than an oil and gas activity, and therefore does not permit related reserves to be included with oil and gas reserves. NI 51-101 specifically includes such activity as an oil and gas activity and recognizes synthetic oil as a product type, and therefore permits them to be included with oil and gas reserves. We have provided a separate table showing our share of the Syncrude proved reserves as well as the additional disclosures relating to mining activities required by SEC requirements.

The foregoing is a general description of the principal differences only.

NI 51-101 requires that we make the following disclosures:

- we use oil equivalents (boe) to express quantities of natural gas and crude oil in a common unit. A conversion ratio of 6 mcf of natural gas to 1 barrel of oil is used. Boe may be misleading, particularly if used in isolation. The conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

In 2005, we built **on** our solid financial position, increasing net income to exceed $1 billion for the first time, strengthening earnings per share to $4.43 and reducing long-term debt by almost $600 million.

see the **value**

financial statements

Item 8. Financial Statements and Supplementary Data

REPORT OF MANAGEMENT

February 7, 2006

To the Shareholders of Nexen Inc.:

We are responsible for the preparation and fair presentation of the consolidated financial statements, as well as the financial reporting process that gives rise to such consolidated financial statements. This responsibility requires us to make significant accounting judgments and estimates. For example, we are required to choose accounting principles and methods that are appropriate to the company's circumstances, and we are required to make estimates and assumptions that affect amounts reported. Fulfilling this responsibility requires the preparation and presentation of our consolidated financial statements in accordance with generally accepted accounting principles in Canada with a reconciliation to generally accepted accounting principles in the US.

We also have responsibility for the preparation and fair presentation of other financial information in this report and to ensure the consistency of this information with the financial statements.

We are responsible for the development and implementation of internal controls over the financial reporting process. These controls are designed to provide reasonable assurance that relevant and reliable financial information is produced. To gather and control financial data, we have established accounting and reporting systems supported by internal controls over financial reporting and an internal audit program. We believe that our internal controls over financial reporting provide reasonable assurance that our assets are safeguarded against loss from unauthorized use or disposition, that receipts and expenditures of the company are made only in accordance with authorization of management and directors of the company, and that our records are reliable for preparing our consolidated financial statements and other financial information in accordance with applicable generally accepted accounting principles and in accordance with applicable securities rules and regulations. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

We have established disclosure controls and procedures, internal controls over financial reporting and corporate-wide policies to ensure that Nexen's consolidated financial position, results of operations and cash flows are presented fairly. Our disclosure controls and procedures are designed to ensure timely disclosure and communication of all material information required by regulators. We oversee, with assistance from our Disclosure Review Committee, these controls and procedures and all required regulatory disclosures.

To ensure the integrity of our financial statements, we carefully select and train qualified personnel. We also ensure our organizational structure provides appropriate delegation of authority and division of responsibilities. Our policies and procedures are communicated throughout the organization and include a written ethics and integrity policy that applies to all employees, including the chief executive officer, chief financial officer and chief accounting officer or controller.

Our Board of Directors is responsible for reviewing and approving the consolidated financial statements and for overseeing management's performance of its financial reporting responsibilities. Their financial statement related responsibilities are fulfilled mainly through the Audit and Conduct Review Committee (the Audit Committee) with assistance from the Reserves Review Committee regarding the annual review of our crude oil and natural gas reserves and the Finance Committee regarding the assessment and mitigation of risk. The Audit Committee is composed entirely of independent directors and includes four directors with financial expertise. The Audit Committee meets regularly with management, the internal auditors and the independent registered Chartered Accountants (independent auditors) to review accounting policies, financial reporting and internal control issues and to ensure each party is properly discharging its responsibilities. The Audit Committee is responsible for the appointment and compensation of the independent auditors and also considers their independence, reviews their fees and (subject to applicable securities laws), pre-approves their retention for any permitted non-audit services and their fee for such services. The internal auditors and independent auditors have full and unlimited access to the Audit Committee, with or without the presence of management.

(signed) "Charles W. Fischer"
President and Chief Executive Officer

(signed) "Marvin F. Romanow"
Executive Vice President and Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of Nexen Inc.:

We have audited the consolidated balance sheets of Nexen Inc. as at December 31, 2005 and 2004 and the consolidated statements of income, cash flows and shareholders' equity for each of the years in the three year period ended December 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). These standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Nexen Inc. as at December 31, 2005 and 2004 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2005 in accordance with Canadian generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as at December 31, 2005, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 7, 2006 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Calgary, Canada
February 7, 2006

(signed) "Deloitte & Touche LLP"
Independent Registered Chartered Accountants

COMMENTS BY AUDITORS ON CANADA-UNITED STATES OF AMERICA REPORTING DIFFERENCE

The standards of the Public Company Accounting Oversight Board (United States) require the addition of an explanatory paragraph (following the opinion paragraph) when there are changes in accounting principles that have a material effect on the comparability of the Company's financial statements, such as the changes described in Note 1(u) to the consolidated financial statements. Our report to the board of directors and shareholders on the consolidated financial statements of Nexen Inc., dated February 7, 2006, is expressed in accordance with Canadian reporting standards which do not require a reference to such changes in accounting principles in the auditors' report when the change is properly accounted for and adequately disclosed in the financial statements.

Calgary, Canada
February 7, 2006

(signed) "Deloitte & Touche LLP"
Independent Registered Chartered Accountants

Nexen Inc.
Consolidated Statement of Income
For the Three Years Ended December 31, 2005

Cdn$ millions, except per share amounts	2005	2004	2003
Revenues and Other Income			
Net Sales	3,932	2,944	2,632
Marketing and Other (Note 17)	702	713	610
Gain on Dilution of Interest in Chemicals Business (Note 2)	193	–	–
	4,827	3,657	3,242
Expenses			
Operating	893	722	688
Depreciation, Depletion, Amortization and Impairment (Note 6)	1,052	674	914
Transportation and Other	796	549	489
General and Administrative	792	299	185
Exploration	250	243	193
Interest (Note 8)	97	143	169
	3,880	2,630	2,638
Income from Continuing Operations before Income Taxes	947	1,027	604
Provision for Income Taxes (Note 18)			
Current	339	248	214
Future	(100)	69	(117)
	239	317	97
Net Income from Continuing Operations before Non-Controlling Interests	708	710	507
Net Income Attributable to Non-Controlling Interests	8	–	–
Net Income from Continuing Operations	700	710	507
Net Income from Discontinued Operations (Note 14)	452	83	71
Net Income	**1,152**	**793**	**578**
Earnings Per Common Share from Continuing Operations ($/share)			
Basic (Note 13)	2.69	2.76	2.05
Diluted (Note 13)	2.63	2.72	2.03
Earnings Per Common Share ($/share)			
Basic (Note 13)	4.43	3.08	2.33
Diluted (Note 13)	4.33	3.04	2.31

See accompanying notes to Consolidated Financial Statements.

Nexen Inc.
Consolidated Balance Sheet
December 31, 2005 and 2004

Cdn$ millions, except share amounts	2005	2004
ASSETS		
Current Assets		
Cash and Cash Equivalents	48	73
Restricted Cash	70	–
Accounts Receivable (Note 4)	3,151	2,100
Inventories and Supplies (Note 5)	504	351
Assets of Discontinued Operations (Note 14)	–	38
Other	51	41
Total Current Assets	3,824	2,603
Property, Plant and Equipment (Note 6)	9,594	8,203
Goodwill	364	375
Future Income Tax Assets (Note 18)	410	333
Deferred Charges and Other Assets (Note 10)	398	429
Assets of Discontinued Operations (Note 14)	–	440
TOTAL ASSETS	**14,590**	**12,383**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-Term Borrowings (Note 8)	–	100
Accounts Payable and Accrued Liabilities	3,710	2,377
Accrued Interest Payable	55	34
Dividends Payable	13	13
Liabilities of Discontinued Operations (Note 14)	–	39
Total Current Liabilities	3,778	2,563
Long-Term Debt (Note 8)	3,687	4,259
Future Income Tax Liabilities (Note 18)	1,960	2,023
Asset Retirement Obligations (Note 9)	590	399
Deferred Credits and Other Liabilities (Note 11)	479	142
Liabilities of Discontinued Operations (Note 14)	–	130
Non-Controlling Interests (Note 2)	88	–
Shareholders' Equity (Note 12)		
Common Shares, no par value		
Authorized: Unlimited		
Outstanding: 2005—261,140,571 shares 2004—258,399,166 shares	732	637
Contributed Surplus	2	–
Retained Earnings	3,435	2,335
Cumulative Foreign Currency Translation Adjustment	(161)	(105)
Total Shareholders' Equity	4,008	2,867
Commitments, Contingencies and Guarantees (Notes 15 and 18)		
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**14,590**	**12,383**

See accompanying notes to Consolidated Financial Statements.

Approved on behalf of the Board:

(signed) "Charles W. Fischer"
Director

(signed) "Thomas C. O'Neill"
Director

Nexen Inc.
Consolidated Statement of Cash Flows
For the Three Years Ended December 31, 2005

Cdn$ millions	2005	2004	2003
Operating Activities			
Net Income from Continuing Operations	700	710	507
Net Income from Discontinued Operations	452	83	71
Charges and Credits to Income not Involving Cash (Note 19)	1,069	906	1,024
Exploration Expense	250	243	193
Changes in Non-Cash Working Capital (Note 19)	(195)	(122)	(320)
Other	(133)	(214)	(70)
	2,143	1,606	1,405
Financing Activities			
Proceeds from Long-Term Notes and Debentures (Note 8)	1,253	1,779	651
Repayment of Long-Term Notes and Debentures (Note 8)	(1,818)	(300)	–
Proceeds from (Repayment of) Term Credit Facilities, Net	(66)	83	93
Proceeds from (Repayment of) Short-Term Borrowings, Net	(99)	101	(18)
Proceeds from Subordinated Debentures (Note 8)	–	–	613
Redemption of Preferred Securities	–	(289)	(340)
Dividends on Common Shares	(52)	(52)	(40)
Issue of Common Shares	58	124	73
Net Proceeds from Canexus Initial Public Offering (Note 2)	301	–	–
Proceeds from Term Credit Facilities of Canexus, Net (Notes 2 and 8)	176	–	–
Other	(27)	(20)	(26)
	(274)	1,426	1,006
Investing Activities			
Business Acquisition, Net of Cash Acquired (Note 3)	–	(2,583)	–
Capital Expenditures			
Exploration and Development	(2,564)	(1,582)	(1,276)
Proved Property Acquisitions	(20)	(4)	(164)
Chemicals, Corporate and Other	(54)	(95)	(54)
Proceeds on Disposition of Assets	911	34	293
Changes in Non-Cash Working Capital (Note 19)	(54)	244	(18)
Changes in Restricted Cash	(70)	–	–
Other	(13)	(27)	–
	(1,864)	(4,013)	(1,219)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(30)	(33)	(164)
Increase (Decrease) in Cash and Cash Equivalents	(25)	(1,014)	1,028
Cash and Cash Equivalents—Beginning of Year	73	1,087	59
Cash and Cash Equivalents—End of Year	**48**	**73**	**1,087**

See accompanying notes to Consolidated Financial Statements.

Nexen Inc.
Consolidated Statement of Shareholders' Equity
For the Three Years Ended December 31, 2005

Cdn$ millions	2005	2004	2003
Common Shares (Note 12)			
Balance at Beginning of Year	637	513	440
Exercise of Stock Options	29	93	50
Issue of Common Shares	29	31	23
Previously Recognized Liability Relating to Stock Options Exercised	37	–	–
Balance at End of Year	**732**	**637**	**513**
Contributed Surplus			
Balance at Beginning of Year	–	1	–
Stock Based Compensation Expense (Note 12)	2	2	1
Modification of Stock Option Plan to Tandem Option Plan (Note 12)	–	(3)	–
Balance at End of Year	**2**	**–**	**1**
Retained Earnings			
Balance at Beginning of Year	2,335	1,594	1,056
Net Income	1,152	793	578
Dividends on Common Shares	(52)	(52)	(40)
Balance at End of Year	**3,435**	**2,335**	**1,594**
Cumulative Foreign Currency Translation Adjustment			
Balance at Beginning of Year	(105)	(33)	94
Translation Adjustment, Net of Income Taxes	(56)	(72)	(127)
Balance at End of Year	**(161)**	**(105)**	**(33)**

See accompanying notes to Consolidated Financial Statements.

Nexen Inc.
Notes to Consolidated Financial Statements

Cdn$ millions except as noted

1. ACCOUNTING POLICIES

Our Consolidated Financial Statements are prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP). The impact of significant differences between Canadian and United States (US) GAAP on the Consolidated Financial Statements is disclosed in Note 21.

(a) Use of estimates

We make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements, and revenues and expenses during the reporting period. Our management reviews these estimates, including those related to accruals, litigation, environmental and asset retirement obligations, income taxes and the determination of proved reserves on an ongoing basis. Changes in facts and circumstances may result in revised estimates, and actual results may differ from these estimates.

(b) Principles of consolidation

The Consolidated Financial Statements include the accounts of Nexen Inc. and our subsidiary companies (Nexen, we or our). All subsidiary companies, with the exception of Canexus LP (see Note 2) and its subsidiaries, are wholly owned and all material intercompany accounts and transactions have been eliminated. On August 18, 2005, we sold our chemicals operations to Canexus LP, but retained effective control of these operations through our 61.4% interest in Canexus LP (see Note 2). All of the assets, liabilities and results of operations of Canexus LP and its subsidiaries have been included in our consolidated financial statements. The non-Nexen ownership interests in Canexus LP and its subsidiaries are shown as non-controlling interests. We proportionately consolidate our undivided interests in our oil and gas exploration, development and production activities conducted under joint venture arrangements. We also proportionately consolidate our 7.23% undivided interest in the Syncrude joint venture, which is considered a mining activity under US regulations. While the joint ventures under which these activities are carried out do not comprise distinct legal entities, they are operating entities, the significant operating policies of which are, by contractual arrangement, jointly controlled by all working interest parties.

(c) Accounts receivable

Accounts receivable are recorded based on our revenue recognition policy (see Note 1(j)). Our allowance for doubtful accounts provides for specific doubtful receivables.

(d) Inventories and supplies

Inventories and supplies for our oil and gas, marketing and chemicals operations are stated at the lower of cost and net realizable value. Cost is determined on the first-in, first-out method or average basis. Inventory costs include expenditures and other costs, including depreciation, depletion and amortization, directly or indirectly incurred in bringing the inventory to its existing condition.

(e) Property, plant and equipment (PP&E)

Property, plant and equipment is recorded at cost and includes only recoverable costs that directly result in an identifiable future benefit. Unrecoverable costs, maintenance and turnaround costs are expensed as incurred. Improvements that increase capacity or extend the useful lives of the related assets are capitalized to PP&E.

We follow successful efforts accounting for our oil and gas business. All property acquisition costs are initially capitalized to PP&E as unproved property costs. Once proved reserves are discovered, the acquisition costs are reclassified to proved property acquisition costs. Exploration drilling costs are capitalized pending evaluation as to whether sufficient quantities of reserves have been found to justify commercial production. If commercial quantities of reserves are not found, exploration drilling costs are expensed. All exploratory wells are evaluated for commercial viability on a regular basis following completion of drilling. Exploration drilling costs remain capitalized when a well has found a sufficient quantity of reserves to justify its completion as a producing well and sufficient progress is being made to assess the reserves and the economic and operating viability of the well. All other exploration costs, including geological and geophysical and annual lease rentals, are expensed to earnings as incurred. All development costs are capitalized as proved property costs. General and administrative costs that directly relate to acquisition, exploration and development activities are capitalized to PP&E.

PP&E for our Syncrude operation is recorded at cost and includes only recoverable costs that directly result in an identifiable future benefit. Unrecoverable costs, maintenance and turnaround costs are expensed as incurred. Improvements that increase capacity or extend the useful lives of the related assets are capitalized to PP&E.

We engage in research and development activities to develop or improve processes and techniques to extract oil and gas. Research involves investigating new knowledge. Development involves translating that knowledge into a new technology or process. Research costs are expensed as incurred. Development costs are deferred once technical feasibility is established, and we intend to proceed with development. We defer these costs in PP&E until the commencement of commercial operations or production. Otherwise, development costs are expensed as incurred. Development costs include pre-operating revenues and costs.

(f) Depreciation, depletion, amortization and impairment (DD&A)

Under successful efforts accounting, we deplete oil and gas capitalized costs using the unit-of-production method. Development and exploration drilling and equipping costs are depleted over remaining proved developed reserves and proved property acquisition costs over remaining proved reserves. Depletion is considered a cost of inventory when the oil and gas is produced. When this inventory is sold, the depletion is charged to DD&A expense.

Our Syncrude PP&E is depleted using the unit-of-production method. Capitalized costs are depleted over proved and probable reserves within developed areas of interest.

We depreciate other plant and equipment costs, including our chemicals facilities, using the straight-line method based on the estimated useful lives of the assets, which range from 3 years to 30 years. Unproved property costs and major projects that are under construction or development are not depreciated, depleted or amortized.

We evaluate the carrying value of our PP&E whenever events or conditions occur that indicate that the carrying value of properties on our balance sheet may not be recoverable from future cash flows. These events or conditions occur periodically. If carrying value exceeds the sum of undiscounted future cash flows, the property's value is impaired. The property is then assigned a fair value equal to its estimated total future cash flows, discounted for the time value of money, and we expense the excess carrying value to depreciation, depletion, amortization and impairment. Our cash flow estimates require assumptions about future commodity prices, operating costs and other factors. Actual results can differ from these estimates.

In assessing the carrying values of our unproved properties, we take into account our future plans for these properties, the remaining terms of the leases and any other factors that may be indicators of potential impairment.

(g) Carried interest

We conduct certain international operations jointly with foreign governments in accordance with production sharing agreements pursuant to which proved reserves are recognized using the economic interest method. Under these agreements, we pay both our share and the government's share of operating and capital costs. We recover the government's share of these costs from future revenues or production over several years. The government's share of operating costs are recorded in operating expense when incurred and capital costs are recorded in PP&E and expensed to DD&A in the year recovered. All recoveries are recorded as revenue in the year of recovery.

(h) Asset retirement obligations

We provide for future asset retirement obligations on our resource properties, facilities, production platforms, pipelines and chemicals facilities based on estimates established by current legislation and industry practices. The asset retirement obligation is initially measured at fair value and capitalized to PP&E as an asset retirement cost. The asset retirement obligation accretes until the time the retirement obligation is expected to settle, while the asset retirement cost is amortized over the useful life of the underlying PP&E. We periodically review our estimates for changes in expected amounts or timing of cash flows.

The amortization of the asset retirement cost and the accretion of the asset retirement obligation are included in depreciation, depletion, amortization and impairment. Actual retirement costs are recorded against the obligation when incurred. Any difference between the recorded asset retirement obligation and the actual retirement costs incurred is recorded as a gain or loss in the period of settlement.

(i) Goodwill

Goodwill is recorded at cost and is not amortized. We test goodwill for impairment annually based on estimated future cash flows of the reporting unit to which the goodwill is attributable. In addition, we test goodwill for impairment whenever an event or circumstance occurs that may reduce the fair value of a reporting unit below its carrying amount. If our goodwill is impaired, we write it down to its implied fair value, based on the fair value of the assets and liabilities of the underlying reporting unit. Our goodwill is attributable to our marketing and UK reporting units.

(j) Revenue recognition

Crude Oil and Natural Gas

Revenue from the production of crude oil and natural gas is recognized when title passes to the customer. In Canada, the US and the UK, our customers primarily take title when the crude oil and natural gas reaches the end of the pipeline. For our other international operations, our customers take title when the crude oil is loaded onto the tanker. When we produce or sell more or less oil or natural gas than our share, production overlifts and underlifts occur. We record overlifts as liabilities and underlifts as assets. We settle these over time as liftings are equalized or in cash when production ends.

Revenue represents Nexen's share and is recorded net of royalty payments to governments and other mineral interest owners. For our international operations, all government interests, except for income taxes, are considered royalty payments. Our revenue also includes the recovery of costs paid on behalf of foreign governments in international locations. See Note 1(g).

Chemicals

Revenue from our chemicals operations is only recognized when our products are delivered to our customers. Delivery only takes place when we have a sales contract in place specifying delivery volumes and sales prices. We assess customer credit worthiness before entering into sales contracts to minimize collection risk.

Marketing

Substantially all of the physical purchase and sales contracts entered into by our marketing operation are considered to be derivative instruments. Accordingly, financial and physical commodity contracts (collectively derivative instruments) held by our marketing operation are stated at fair value on the balance sheet unless the requirements for hedge accounting are met (see Note 1(n)). We record any change in fair value as a gain or loss in marketing and other.

Any margin realized by our marketing operation on the sale of our proprietary oil and gas production is included in marketing and other. We assess customer credit worthiness before entering into contracts and provide for netting terms to minimize collection risk. Amounts are recorded on a net basis where we have the legal right of offset. Our marketing operation has received cash payments in exchange for assuming certain transportation obligations from third parties. These cash payments have been recorded as deferred liabilities and are recognized in net income as the transportation is used.

(k) Income taxes

We follow the liability method of accounting for income taxes (see Note 18). This method recognizes income tax assets and liabilities at current rates, based on temporary differences in reported amounts for financial statement and tax purposes. The effect of a change in income tax rates on future income tax assets and future income tax liabilities is recognized in income when substantively enacted.

We do not provide for foreign withholding taxes on the undistributed earnings of our foreign subsidiaries, as we intend to invest such earnings indefinitely in foreign operations.

(l) Foreign currency translation

Our foreign operations, which are considered financially and operationally independent, are translated from their functional currency into Canadian dollars as follows:

- assets and liabilities using exchange rates at the balance sheet dates; and
- revenues and expenses using average exchange rates throughout the year.

Gains and losses resulting from this translation are included in the cumulative foreign currency translation adjustment in shareholders' equity.

Monetary balances denominated in a currency other than a functional currency are translated into the functional currency using exchange rates at the balance sheet dates. Gains and losses arising from this translation, except on our designated US-dollar debt, are included in income. We have designated our US-dollar debt as a hedge against our net investment in US-dollar based self-sustaining foreign operations. Gains and losses resulting from the translation of the designated US-dollar debt are included in the cumulative foreign currency translation adjustment in shareholders' equity. If our US-dollar debt, net of income taxes, exceeds our US-dollar investment in foreign operations, then the gains or losses attributable to such excess are included in marketing and other in the Consolidated Statement of Income.

(m) Capitalized interest

We capitalize interest on major development projects until the project is substantially complete using the weighted-average interest rate on all of our borrowings. Capitalized interest cannot exceed the actual interest expense.

(n) Derivative instruments

Non-Trading Activities

We use derivative instruments such as physical purchase and sales contracts, forwards, futures, swaps and options for non-trading purposes to manage fluctuations in commodity prices, foreign currency exchange rates and interest rates (see Note 7). We record these instruments at fair value at the balance sheet date and record any change in fair value as a net gain or loss in marketing and other during the period of change unless the requirements for hedge accounting are met. Hedge accounting is used when there is a high degree of correlation between price movements in the derivative instruments and the items designated as being hedged. Nexen formally documents all hedges and the risk management objectives at the inception of the hedge. We recognize gains and losses on the derivative instruments designated as hedges in the same period as the gains or losses on the hedged items are recognized. If effective correlation ceases, hedge accounting is terminated, and future changes in the market value of the derivative instrument are included as gains or losses in marketing and other in the period of change.

Trading Activities

Our marketing operation uses derivative instruments for marketing and trading crude oil and natural gas including:

- commodity contracts settled with physical delivery;
- exchange-traded futures and options; and
- non-exchange traded forwards, swaps and options.

We record these instruments at fair value at the balance sheet date and record changes in fair value as net gains or losses in marketing and other during the period of change. The fair value of these instruments is recorded as accounts receivable or payable if we anticipate settling the instruments within a year of the balance sheet date. If we anticipate settling the instruments beyond 12 months, we record them as deferred charges and other assets or deferred credits and other liabilities.

(o) Employee future benefits

The cost of pension benefits earned by employees in our defined benefit pension plans is actuarially determined using the projected-benefit method prorated on service and our best estimate of the plans' investment performance, salary escalations and retirement ages of employees. To calculate the plans' expected returns, assets are measured at fair value. Past service costs arising from plan amendments, and net actuarial gains and losses that exceed 10% of the greater of the accrued benefit obligation and the fair value of plan assets, are expensed in equal amounts over the expected average remaining service life of the employee group. We measure the plan assets and the accrued benefit obligation on October 31 each year.

(p) Stock-based compensation

In 2003, we adopted the fair-value method of accounting for stock options granted to employees and directors. We recorded stock-based compensation expense in the Consolidated Statement of Income as general and administrative expenses for all options granted on or after January 1, 2003, with a corresponding increase to contributed surplus. Compensation expense for options granted was based on estimated fair values at the time of grant and we recognized the expense over the vesting period of the option.

In May 2004, we modified our stock option plan to a tandem option plan by including a cash feature. The tandem options give the holders a right to either purchase common shares at the exercise price or to receive cash payments equal to the excess of the market value of the common shares over the exercise price. As a result of the modification, we record obligations for the tandem options using

the intrinsic-value method of accounting and recognize compensation expense. Obligations are accrued on a graded vesting basis and represent the difference between the market value of our common shares and the exercise price of the options. The obligations are revalued each reporting period based on the change in the market value of our common shares and the number of graded vested options outstanding. We reduce the liability when the options are surrendered for cash. When the options are exercised for stock, the recorded liability amount is transferred to share capital.

Stock options awarded to our US employees between December 1, 2004 and December 1, 2005 do not include a cash feature and are not accounted for as tandem options. Instead, we account for these options using the fair-value method. Compensation expense is based on estimated fair values at the time of grant and is recognized over the vesting period of the options. The expense is included as general and administrative expense with a corresponding increase to contributed surplus. Stock options awarded to our US employees after December 1, 2005 are accounted for as tandem options.

We provide stock appreciation rights to employees as described in Note 12, and we account for these on the same basis as our tandem options. Obligations are accrued as compensation expense over the graded vesting period of the stock appreciation rights.

(q) Cash and cash equivalents

Cash and cash equivalents include short-term, highly liquid investments that mature within three months of their purchase. They are recorded at cost, which approximates market value.

(r) Restricted cash

Restricted cash includes margin deposits relating to our exchange-traded derivative contracts and other cash balances subject to regulatory restrictions.

(s) Leases

We classify leases entered into as either capital or operating leases. Leases that transfer substantially all of the benefits and risks of ownership to us are accounted for as capital leases and included with PP&E. These assets are depreciated on the same basis as other PP&E. Rental payments under operating leases are expensed as incurred.

(t) Transportation

We pay to transport the crude oil, natural gas and chemicals products that we market, and then bill our customers for the transportation. This transportation is presented in our Consolidated Financial Statements as a cost to us and is recorded as transportation and other.

(u) Changes in accounting principles

Financial Instruments

In the fourth quarter of 2004, we retroactively adopted the changes to CICA standard S.3860, *Financial Instruments*. These changes require that fixed-amount contractual obligations that can be settled by issuing a variable number of equity instruments be classified as a liability. Our US-dollar denominated preferred and subordinated securities have these characteristics and accordingly have been reclassified as long-term debt. Dividends and interest on these securities have been included in interest expense, and issue costs previously charged to retained earnings have been amortized over the life of the securities. Unamortized issue costs have been expensed on the redemption of the preferred securities in 2003 and 2004. Foreign exchange gains or losses from translation of the US-dollar denominated preferred and subordinated securities have been included as cumulative foreign currency translation adjustments.

Generally Accepted Accounting Principles

In 2004, we adopted CICA standard S.1100, *Generally Accepted Accounting Principles* which eliminated general practice in Canada as a component of GAAP. Our accounting policy for 2005 and 2004 is to include geological and geophysical costs as operating cash outflows in our Consolidated Statement of Cash Flows. For previous years, we included geological and geophysical costs as investing cash outflows consistent with industry practice in Canada. In our Consolidated Statement of Cash Flows for 2005 and 2004, we included $53 and $73 million, respectively, of geological and geophysical costs as other operating cash outflows. For 2003, geological and geophysical costs of $62 million are included in investing activities as exploration and development capital expenditures. This change in accounting policy was adopted prospectively.

(v) Reclassification

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2005.

2. CANEXUS INCOME FUND

In June 2005, our board of directors approved a plan to monetize our chemicals operations through the creation of an income trust and the issuance of trust units in an initial public offering. This initial public offering closed on August 18, 2005, with Canexus Income Fund (Canexus) issuing 30 million units at a price of $10 per unit for gross proceeds of $300 million ($284 million, net of underwriters' commissions).

Concurrent with the closing of the offering, Canexus acquired a 36.5% interest in Canexus Limited Partnership (Canexus LP) using the net proceeds from the initial public offering. Canexus LP acquired Nexen's chemicals business for approximately $1 billion, comprised of the net proceeds from Canexus' initial public offering and $200 million (US$167 million) of bank debt, plus the issuance of 52.3 million exchangeable limited partnership units (Exchangeable LP Units) of Canexus LP. At that time, the Exchangeable LP Units held by Nexen represented a 63.5% interest in Canexus LP.

The Exchangeable LP Units held by Nexen are exchangeable on a one-for-one basis for trust units of Canexus. As a result, the Exchangeable LP Units owned by Nexen were exchangeable into 52.3 million trust units which represented 63.5% of the outstanding trust units of Canexus assuming exchange of the Exchangeable LP Units.

On September 16, 2005, the underwriters of the initial public offering exercised a portion of their over-allotment option to purchase 1.75 million trust units at $10 per unit for gross proceeds of $18 million ($17 million, net of underwriters' commissions). As a result, Nexen exchanged 1.75 million of its Exchangeable LP Units for $17 million in net proceeds. After this exchange, Nexen has a 61.4% interest in Canexus LP represented by 50.5 million Exchangeable LP Units. The initial public offering, together with the exercise of the over-allotment, resulted in total net proceeds to Nexen of $301 million.

These transactions diluted our interest in our chemicals operations. As a result of this dilution, we recorded a gain of $193 million during the third quarter of 2005.

We have the right to nominate a majority of the members of the board of Canexus Limited, the corporation with responsibility for the strategic management and operational decisions of Canexus and Canexus LP. Nexen has nominated two representatives to the 10-member board of Canexus Limited. Since we have retained effective control of our chemicals business, the results, assets and liabilities of this business have been included in these financial statements. The non-Nexen ownership interests in our chemicals business are shown as non-controlling interests.

3. BUSINESS ACQUISITION

On December 1, 2004, we acquired 100% of the issued and outstanding share capital of EnCana (UK) Limited (EnCana UK) from EnCana Corporation (EnCana) for cash consideration of US$2.1 billion, subject to certain adjustments. EnCana UK held all of EnCana's offshore oil and gas assets in the North Sea.

We acquired EnCana UK to establish a strategic presence in the North Sea by acquiring operatorship of the Buzzard field development and operatorship of the producing Scott and Telford fields. The acquisition also gave us access to interests in several satellite discoveries and more than 700,000 net undeveloped exploration acres. In addition, we acquired the management and technical teams that found and are developing the Buzzard discovery. Goodwill paid was attributable to the established North Sea presence acquired and the knowledge and business relationships acquired through the management team and employees of EnCana UK.

The acquisition has been accounted for using the purchase method, and the results of EnCana UK have been consolidated with the results of Nexen from December 1, 2004. The following table shows the allocation of the purchase price based on the estimated fair values of the assets and liabilities acquired:

Purchase Price, Net of Cash Acquired:	
Cash Paid	2,561
Transaction Costs	22
Total Purchase Price	**2,583**
Purchase Price Allocated as follows:	
Accounts Receivable	310
Inventories and Supplies	11
Other Current Assets	2
Property, Plant and Equipment	3,395
Future Income Tax Assets	239
Goodwill [1]	334
Deferred Charges and Other Assets	12
Accounts Payable and Accrued Liabilities	(289)
Asset Retirement Obligations	(134)
Future Income Tax Liabilities	(1,284)
Deferred Credits and Other Liabilities	(13)
Total Purchase Price Allocated	**2,583**

Note:
1 The amount of goodwill deductible for tax purposes is nil.

The unaudited pro forma results for the years ended December 31, 2004 and 2003 are shown below as if the acquisition had occurred on January 1, 2003. Pro forma results are not necessarily indicative of actual results or future performance.

	2004	2003
Revenues	4,258	3,642
Net Income	841	595
Earnings Per Common Share—Basic ($/share)	3.27	2.40
Earnings Per Common Share—Diluted ($/share)	3.23	2.38

4. ACCOUNTS RECEIVABLE

	2005	2004
Trade		
Marketing	2,400	1,452
Oil and Gas	614	557
Chemicals and Other	48	57
	3,062	2,066
Non-Trade	96	49
	3,158	2,115
Allowance for Doubtful Receivables	(7)	(15)
Total Accounts Receivable	**3,151**	**2,100**

5. INVENTORIES AND SUPPLIES

	2005	2004
Finished Products		
Marketing	320	199
Oil and Gas	11	6
Chemicals and Other	15	13
	346	218
Work in Process	6	4
Field Supplies	152	129
Total Inventories and Supplies	**504**	**351**

6. PROPERTY, PLANT AND EQUIPMENT

	2005			2004		
	Cost	Accumulated DD&A	Net Book Value	Cost	Accumulated DD&A	Net Book Value
Oil and Gas						
Yemen	833	546	287	678	506	172
Yemen—Carried Interest	1,410	1,295	115	1,360	1,044	316
Canada	3,631	1,311	2,320	2,603	1,195	1,408
United States	2,437	1,159	1,278	2,249	1,037	1,212
United Kingdom	4,013	216	3,797	3,499	16	3,483
Other Countries	249	119	130	535	408	127
Marketing	177	72	105	157	64	93
	12,750	4,718	8,032	11,081	4,270	6,811
Syncrude	1,240	171	1,069	1,030	155	875
Chemicals	827	456	371	815	409	406
Corporate and Other	245	123	122	201	90	111
Total PP&E	**15,062**	**5,468**	**9,594**	**13,127**	**4,924**	**8,203**

The above table includes capitalized costs of $5,211 million (2004—$3,945 million) relating to unproved properties and projects under construction or development. These costs are not being depreciated, depleted or amortized.

Depreciation, Depletion, Amortization and Impairment

Included in our 2005 depreciation, depletion, amortization and impairment expense was $58 million relating to the writedown of a portion of our purchase price allocation to unproved properties purchased in the North Sea as a result of unsuccessful exploration activities.

Our 2003 depreciation, depletion, amortization and impairment expense in the Consolidated Statement of Income includes an impairment charge of $269 million relating to certain Canadian oil and gas properties. The impairment resulted from negative reserve revisions and was largely attributable to Canadian heavy oil properties. The revisions resulted from changes in late field-life economic assumptions, changes in proved undeveloped reserves based on drilling results and geological mapping, and reassessments of estimated future production profiles.

Research and Development

We incurred $54 million (2004—$35 million) related to research and development activities. Costs of $44 million (2004—$26 million) were recorded in other expense on the Consolidated Statement of Income. The remaining costs have been deferred and are included in PP&E.

	2005	2004
Development Costs Deferred, Beginning of Year	15	6
Deferred in the Year	10	9
Amortized in the Year	–	–
Development Costs Deferred, End of Year	**25**	**15**

Suspended Well Costs

In the third quarter of 2005, we adopted staff position 19-1 (FSP 19-1) issued by the Financial Accounting Standards Board (FASB) on accounting for suspended well costs. FSP 19-1 amends FASB Statement No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*, for companies using the successful efforts method of accounting, which required that capitalized exploratory well costs be expensed if related reserves could not be classified as proved within one year. FSP 19-1 provides that exploratory well costs should continue to be capitalized when a well has found a sufficient quantity of reserves to justify its completion as a producing well and sufficient progress is being made to assess the reserves and the economic and operating viability of the well. FSP 19-1 also requires certain disclosures with respect to capitalized exploratory well costs.

The following table shows the changes in capitalized exploratory well costs during the years ended December 31, 2005 and 2004, and does not include amounts that were initially capitalized and subsequently expensed in the same period.

	2005	2004
Balance at Beginning of Year	116	89
Additions to Capitalized Exploratory Well Costs Pending the Determination of Proved Reserves	174	51
Capitalized Exploratory Well Costs Charged to Expense	(27)	(19)
Transfers to Wells, Facilities and Equipment Based on Determination of Proved Reserves	(3)	–
Effects of Foreign Exchange	(8)	(5)
Balance at End of Year	**252**	**116**

The following table provides an aging of capitalized exploratory well costs based on the date drilling was completed and shows the number of projects for which exploratory well costs have been capitalized for a period greater than one year after the completion of drilling.

	2005	2004
Capitalized for a Period of One Year or Less	165	53
Capitalized for a Period of Greater than One Year	87	63
Balance at End of Year	**252**	**116**
Number of Projects that have Exploratory Well Costs Capitalized for a Period Greater than One Year	3	2

As at December 31, 2005, we have exploratory costs that have been capitalized for more than one year relating to our interest in an exploratory block, offshore Nigeria ($74 million), our interest in exploratory blocks in the Gulf of Mexico ($4 million) and coal bed methane exploratory activities in Canada ($9 million). Exploratory costs offshore Nigeria were first capitalized in 1998, and we have subsequently drilled a further seven successful wells on the block. The joint venture partners have finalized pre-development design studies and have submitted a field development plan for government approval. Drilling activity has resumed and an appraisal and exploration program is in progress. When final regulatory approvals have been received and the project has been sanctioned, we will book proved reserves. We have capitalized costs related to successful wells drilled in 2004 and 2005 in the Gulf of Mexico, and in Canada, we have capitalized exploratory costs relating to our coal bed methane projects. We are assessing all of these wells and projects, and we are working with our partners to prepare development plans.

7. DERIVATIVE INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

(a) Carrying value and estimated fair value of derivative and financial instruments

The carrying values, fair values and unrecognized gains or losses on our outstanding derivatives and long-term financial assets and liabilities at December 31 are:

	2005			2004		
(Cdn$ millions)	Carrying Value	Fair Value	Unrecognized Gain (Loss)	Carrying Value	Fair Value	Unrecognized Gain (Loss)
Commodity Price Risk						
Non-Trading Activities						
Crude Oil Put Options	4	4	–	200	200	–
Fixed Price Natural Gas Contracts	(175)	(175)	–	–	(98)	(98)
Natural Gas Swaps	29	29	–	–	–	–
Trading Activities						
Crude Oil and Natural Gas	161	161	–	83	83	–
Future Sale of Gas Inventory	–	(35)	(35)	–	6	6
Foreign Currency Risk						
Non-Trading Activities	14	14	–	7	7	–
Trading Activities	8	8	–	10	10	–
Total Derivatives	**41**	**6**	**(35)**	**300**	**208**	**(92)**
Financial Assets and Liabilities						
Long-Term Debt	(3,687)	(3,863)	(176)	(4,259)	(4,503)	(244)

The estimated fair value of all derivative instruments is based on quoted market prices and, if not available, on estimates from third-party brokers or dealers. The carrying value of cash and cash equivalents, restricted cash, amounts receivable and short-term obligations approximates their fair value because the instruments are near maturity.

(b) Commodity price risk management

Non-Trading Activities

We generally sell our crude oil and natural gas under short-term market-based contracts.

Crude oil put options

We purchased WTI crude oil put options to manage the commodity price risk exposure of a portion of our oil production in 2005 and 2006. These options established an annual average WTI floor price of US$43/bbl in 2005 and US$38/bbl in 2006 at a cost of $144 million. The WTI crude oil put options with respect to 2005 production were not used and have expired. The WTI crude oil put options with respect to 2006 production are stated at fair value and are included in deferred charges and other assets as they settle beyond 12 months of December 31, 2005. Any change in fair value is included in marketing and other on the Consolidated Statement of Income.

WTI Crude Oil Put Options	Notional Volumes (bbls/d)	Term	Average Price (WTI) (US$/bbl)	Fair Value (Cdn$ millions)
	30,000	2006	39	2
	20,000	2006	38	1
	10,000	2006	36	1
				4

Fixed-price natural gas contracts and natural gas swaps

In July and August 2005, we sold certain Canadian oil and gas properties, and we retained fixed-price natural gas sales contracts that were previously associated with those properties (see Note 14).

Since these contracts are no longer used in the normal course of our oil and gas operations, they have been marked-to-market and are included in the Consolidated Balance Sheet. Any change in fair value is included in marketing and other in the Consolidated Statement of Income.

	Notional Volumes (Gj/d)	Term	Price ($/Gj)	Fair Value (Cdn$ millions)
Fixed-Price Natural Gas Contracts	22,034	2005–2006	2.28–3.72	(47)
	15,514	2007–2010	2.47–2.77	(128)
				(175)

Following the sale of the Canadian oil and gas properties, we entered into natural gas swaps to economically hedge our exposure to the fixed-price natural gas contracts. Any change in fair value is included in marketing and other in the Consolidated Statement of Income.

	Notional Volumes (Gj/d)	Term	Price ($/Gj)	Fair Value (Cdn$ millions)
Natural Gas Swaps	22,034	2005–2006	9.02–11.81	1
	15,514	2007–2010	7.45	28
				29

Trading Activities

Crude oil and natural gas

We enter into physical purchase and sales contracts as well as financial commodity contracts to enhance our price realizations and lock-in our margins. The physical and financial commodity contracts (derivative contracts) are stated at market value. The $161 million fair value of the commodity contracts at December 31, 2005 is included in the Consolidated Balance Sheet and any change in fair value is included in marketing and other in the Consolidated Statement of Income.

Future sale of gas inventory

We have certain NYMEX futures contracts and swaps in place, which effectively lock-in our margins on the future sale of our natural gas inventory in storage. We have designated, in writing, some of these derivative contracts as cash flow hedges of the future sale of our storage inventory. As a result, gains and losses on these designated futures contracts, and swaps are recognized in net income when the inventory in storage is sold. The principal terms of these outstanding contracts and the unrecognized gains and losses at December 31, 2005 are:

	Hedged Volumes (mmcf)	Month	Average Price (US$/mcf)	Unrecognized Loss (Cdn$ millions)
NYMEX Natural Gas Futures	9,100	January 2006	8.89	(27)
	400	February 2006	10.96	–
NYMEX Natural Gas Fixed-Price and Basis Swaps	4,529	January 2006	9.15	(8)
				(35)

(c) Foreign currency exchange rate risk management

Non-Trading Activities

	Amount	Term	Rate (for US$1.00)	Fair Value (Cdn$ millions)
Foreign Currency Call Options—Buzzard (i)	£207 million	2006	2.00	–
US Dollar Call Options—Canexus (ii)	US$11 million monthly	2006	0.813	6
Foreign Currency Swap (iii)	US$37 million	2006	0.736	8
				14

(i) Foreign currency call options—Buzzard

Our Buzzard development project in the North Sea creates foreign currency exposure as a portion of the capital costs are denominated in British pounds and Euros. To reduce our exposure to fluctuations in these currencies relative to the US dollar, we purchased foreign currency call options in early 2005, which effectively set a ceiling on most of our British pound and Euro spending exposure from March 2005 through to the end of 2006. Any change in fair value is included in marketing and other in the Consolidated Statement of Income.

(ii) US dollar call options—Canexus

The operations of Canexus are exposed to changes in the US-dollar exchange rate as a portion of its sales are denominated in US dollars. In connection with the initial public offering of Canexus, we purchased US-dollar call options to reduce this exposure to fluctuations in the Canadian-US dollar exchange rate. Canexus has the right to sell US$11 million monthly and purchase Canadian dollars at an exchange rate of US$0.813 until August 2006. Any change in fair value is included in marketing and other in the Consolidated Statement of Income.

(iii) Foreign currency swap

We occasionally use derivative instruments to effectively convert cash flows from Canadian to US dollars and vice versa. At December 31, 2005, we held a foreign currency derivative instrument that obligates us and the counterparty to exchange principal and interest amounts. In November 2006, we will pay US$37 million and receive Cdn$50 million (see Note 8). Any change in fair value is included in marketing and other in the Consolidated Statement of Income.

Other

The foreign exchange gains or losses related to our designated debt are included in the cumulative foreign currency translation adjustment in shareholders' equity. Our net investment in self-sustaining foreign operations and our designated US-dollar debt at December 31 are as follows:

(US$ millions)	2005	2004
Net Investment in Self-Sustaining Foreign Operations	4,357	3,973
US-Dollar Debt	2,700	3,315

We also have small exposures to currencies other than the US dollar. A portion of our capital spending on our Long Lake project is denominated in Euros and Japanese Yen. A portion of our United Kingdom operating expenses and capital spending is denominated in British pounds and Euros. We do not have any material exposure to highly inflationary foreign currencies.

Trading Activities

Our sales and purchases of crude oil and natural gas are generally transacted in or referenced to the US dollar, as are most of the financial commodity contracts used by our marketing group. We enter into forward contracts to sell US dollars. When combined with certain commodity sales contracts, either physical or financial, these forward contracts enable us to lock-in our margins on the future sale of crude oil and natural gas. The $8 million fair value of our US-dollar forward contracts and swaps at December 31, 2005 is included in the Consolidated Balance Sheet, and any change in fair value is included in marketing and other in the Consolidated Statement of Income.

(d) Total carrying value of derivative contracts related to trading activities

Amounts related to derivative instruments held by our marketing operation are equal to fair value as we use mark-to-market accounting, and are as follows at December 31:

(Cdn$ millions)	2005	2004
Accounts Receivable	382	177
Deferred Charges and Other Assets [1] (Note 10)	232	91
Total Derivative Contract Assets	**614**	**268**
Accounts Payable and Accrued Liabilities	321	129
Deferred Credits and Other Liabilities [1] (Note 11)	124	46
Total Derivative Contract Liabilities	**445**	**175**
Total Derivative Contract Net Assets [2]	**169**	**93**

Notes:

1 These derivative instruments settle beyond 12 months and are considered non-current.

2 Comprised of $161 million (2004—$83 million) related to commodity contracts and $8 million (2004—$10 million) related to US-dollar forward contracts and swaps.

Our exchange-traded derivative contracts are subject to margin deposit requirements. We are required to advance cash to counterparties in order to satisfy these requirements. We did not have any margin deposit requirements at December 31, 2005 and 2004.

(e) Interest rate risk management

We use fixed and floating rate debt to finance our operations. The floating rate debt exposes us to changes in interest payments as interest rates fluctuate. To manage this exposure, we maintain a combination of fixed and floating rate borrowings and facilities. At December 31, 2005, fixed-rate borrowings comprised 95% (2004—56%) of our long-term debt at an effective average rate of 6.3% (2004—6.6%). During the year we periodically drew on our floating rate unsecured syndicated term credit facilities. We had no interest rate swaps outstanding in 2005 or 2004.

(f) Credit risk management

A substantial portion of our accounts receivable are with counterparties in the energy industry and are subject to normal industry credit risk. This concentration of risk within the energy industry is reduced because of our broad base of domestic and international counterparties. We assess the financial strength of our counterparties, including those involved in marketing and other commodity arrangements, and we limit the total exposure to individual counterparties. As well, a number of our contracts contain provisions that allow us to demand the posting of collateral in the event downgrades to non-investment grade credit ratings occur. Credit risk, including credit concentrations, is routinely reported to our Risk Management Committee. We also use standard agreements that allow for the netting of exposures associated with a single counterparty. We believe this minimizes our overall credit risk.

8. LONG-TERM DEBT AND SHORT-TERM BORROWINGS

	2005	2004
Acquisition Credit Facilities (a)	–	1,806
Canexus LP Term Credit Facilities (US$147 million drawn) (b)	171	–
Term Credit Facilities (c)	–	87
Debentures, due 2006 [1] (d)	93	93
Medium-Term Notes, due 2007 (e)	150	150
Medium-Term Notes, due 2008 (f)	125	125
Notes, due 2013 (US$500 million) (g)	583	602
Notes, due 2015 (US$250 million) (h)	292	–
Notes, due 2028 (US$200 million) (i)	233	241
Notes, due 2032 (US$500 million) (j)	583	602
Notes, due 2035 (US$790 million) (k)	921	–
Subordinated Debentures, due 2043 (US$460 million) (l)	536	553
Total	**3,687**	**4,259**

Note:

1 Includes $50 million of principal that was effectively converted through a currency exchange contract to US$37 million.

(a) Acquisition credit facilities

During the year, we repaid all amounts outstanding under our acquisition credit facilities, which were used to fund a portion of the purchase price for the acquisition of EnCana UK in 2004. We replaced the US$500 million development facility associated with the acquisition credit facilities with the renewal of our term credit facilities. During 2005, the weighted average interest rate on the acquisition credit facilities was 3.9% (2004—3.2%).

(b) Canexus LP term credit facilities

Canexus LP has $350 million of committed, secured, revolving term credit facilities, which are available until 2009. At December 31, 2005, US$147 million ($171 million) was drawn on these facilities. Borrowings are available as Canadian bankers' acceptances, LIBOR-based loans, Canadian prime rate loans or US-dollar base rate loans. Interest is payable monthly at a floating rate. The term credit facilities are secured by a floating charge debenture over all of Canexus LP's assets and by certain guarantees, security interests and subordination agreements provided by certain affiliates of Canexus LP (which do not include Nexen). During 2005, the weighted-average interest rate on the Canexus LP term credit facilities was 4.8%.

(c) Term credit facilities

We have committed, unsecured, term credit facilities of $2.4 billion, which are available until 2010. The lenders have the option to extend the term annually. Borrowings are available as Canadian bankers' acceptances, LIBOR-based loans, Canadian prime loans, US-dollar base rate loans or British pound call-rate loans. Interest is payable monthly at a floating rate. During 2005, the weighted-average interest rate was 4.4% (2004—3.2%). At December 31, 2005, $250 million of these facilities were utilized to support letters of credit.

(d) Debentures, due 2006

During November 1996, we issued $100 million of unsecured 10-year redeemable debentures. Interest is payable semi-annually at a rate of 6.85% and the principal is to be repaid in November 2006. In December 1996, $50 million of this obligation was effectively converted through a currency exchange contract with a Canadian chartered bank to a US$37 million liability bearing interest at 6.75% for the term of the debentures. We may redeem part or all of the debentures at any time. The redemption price will be the greater of par and an amount that provides the same yield as a Government of Canada Bond having a term to maturity equal to the remaining term of the debentures plus 0.1%. Amounts due November 2006 have not been included in current liabilities as we expect to refinance this amount with our term credit facilities.

(e) Medium-term notes, due 2007

During July 1997, we issued $150 million of notes. Interest is payable semi-annually at a rate of 6.45%, and the principal is to be repaid in July 2007. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a Government of Canada Bond having a term to maturity equal to the remaining term of the notes plus 0.125%.

(f) Medium-term notes, due 2008

During October 1997, we issued $125 million of notes. Interest is payable semi-annually at a rate of 6.3%, and the principal is to be repaid in June 2008. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a Government of Canada Bond having a term to maturity equal to the remaining term of the notes plus 0.125%.

(g) Notes, due 2013

During November 2003, we issued US$500 million of notes. Interest is payable semi-annually at a rate of 5.05%, and the principal is to be repaid in November 2013. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes plus 0.2%.

(h) Notes, due 2015

During March 2005, we issued US$250 million of notes. Interest is payable semi-annually at a rate of 5.20%, and the principal is to be repaid in March 2015. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes plus 0.15%.

(i) Notes, due 2028

During April 1998, we issued US$200 million of notes. Interest is payable semi-annually at a rate of 7.4%, and the principal is to be repaid in May 2028. We may redeem part or all of the notes any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes plus 0.25%.

(j) Notes, due 2032

During March 2002, we issued US$500 million of notes. Interest is payable semi-annually at a rate of 7.875%, and the principal is to be repaid in March 2032. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes plus 0.375%.

(k) Notes, due 2035

During March 2005, we issued US$790 million of notes. Interest is payable semi-annually at a rate of 5.875%, and the principal is to be repaid in March 2035. We may redeem part or all of the notes at any time. The redemption price will be the greater of par and an amount that provides the same yield as a US Treasury security having a term to maturity equal to the remaining term of the notes plus 0.2%.

(l) Subordinated debentures, due 2043

During November 2003, we issued US$460 million of unsecured subordinated debentures. Interest is payable quarterly in cash at a rate of 7.35%, and the principal is to be repaid in November 2043. We may redeem part or all of the debentures at any time on or after November 8, 2008. The redemption price is equal to the par value of the principal amount plus any accrued and unpaid interest to the redemption date. We may choose to redeem the principal amount with either cash or common shares.

(m) Debt repayments

2006	93
2007	150
2008	125
2009	171
2010	–
Thereafter	3,148
Total Debt Repayments	**3,687**

(n) Debt covenants

Some of our debt instruments contain covenants with respect to certain financial ratios and our ability to grant security. At December 31, 2005, we were in compliance with all covenants.

(o) Short-term borrowings

Nexen has uncommitted, unsecured credit facilities of approximately $732 million. No amounts were drawn under these facilities at December 31, 2005 (2004—$100 million). We have utilized $468 million of these facilities to support letters of credit at December 31, 2005. Interest is payable at floating rates. During 2005, the weighted-average interest rate on our short-term borrowings was 3.6% (2004—2.9%).

[illegible]

	200[illegible]	200[illegible]	200[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	14[illegible]	16[illegible]

[illegible]

[illegible]

[illegible]

	200[illegible]	200[illegible]
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]
[illegible]	6[illegible]	468

[illegible]

1. [illegible] have been included in accounts payable and accrued liabilities. Obligations related to [illegible]
2. [illegible] million) and obligations relating to our chemicals business amount to [illegible]

[illegible] risk-free rate of [illegible]%. Approximately $88 million included in our asset [illegible]

[illegible] obligations associated with the assets sold. This is included on our balance sheet as part of deferred charges [illegible]

[illegible] asset retirement obligations cannot be reasonably determined because [illegible] determine when remediation activities would take place. These assets [illegible] The estimated future recoverable reserves at Syncrude are significant [illegible] asset retirement activities would take place. Furthermore, the [illegible] ongoing maintenance activities. The retirement obligations for these assets will be [illegible] determinable.

[illegible]

	2005	2004
[illegible]	262	91
[illegible]	6[illegible]	67
[illegible]	14	–
[illegible]	4	200
[illegible]	–	13
[illegible]	85	58
Total	398	429

11. DEFERRED CREDITS AND OTHER LIABILITIES

	2005	2004
Fixed-Price Natural Gas Contracts (Note 7b)	128	–
Long-Term Marketing Derivative Contracts (Note 7d)	124	46
Deferred Transportation	87	33
Stock-Based Compensation Liability	53	–
Defined Benefit Pension Obligation (Note 16)	39	32
Other	48	31
Total	**479**	**142**

12. SHAREHOLDERS' EQUITY

(a) Authorized capital

Authorized share capital consists of an unlimited number of common shares of no par value, and an unlimited number of Class A preferred shares of no par value, issuable in series.

Our shareholders approved a split of our issued and outstanding common shares on a two-for-one basis at our annual and special meeting on April 27, 2005. All common shares, per common share amounts, stock options and stock appreciation rights together with their related weighted-average exercise prices, have been restated to retroactively reflect the share split.

(b) Issued common shares and dividends

(thousands of shares)	2005	2004	2003
Beginning of Year	258,399	251,212	245,932
Issue of Common Shares for Cash			
Exercise of Stock Options	1,823	5,902	3,928
Dividend Reinvestment Plan	605	895	952
Employee Flow-through Shares	314	390	400
End of Year	**261,141**	**258,399**	**251,212**
Dividends Declared per Common Share ($/share)	**0.20**	**0.20**	**0.1625**
Cash Consideration (Cdn$ millions)			
Exercise of Stock Options	29	93	50
Dividend Reinvestment Plan	20	21	15
Employee Flow-through Shares	9	10	8
	58	**124**	**73**

At December 31, 2005, there were 774,915 common shares (2004–1,379,874; 2003–2,274,610) reserved for issuance under the Dividend Reinvestment Plan.

(c) Stock options

In May 2004, our shareholders approved the modification of our stock option plan to a tandem option plan by including a cash feature. The tandem options give the holders a right to either purchase common shares at the exercise price or to receive cash payments equal to the excess of the market value of the common shares over the exercise price.

Similar to our stock appreciation rights, we use the intrinsic-value method to recognize compensation expense associated with our tandem options. Obligations are accrued on a graded vesting basis and represent the difference between the market value of our common shares and the exercise price of the options. The obligations are revalued each reporting period based on the change in the market value of our common shares and the number of graded vested options outstanding.

Upon modification of the stock option plan, we were required to recognize an obligation for our tandem options. This obligation represented the difference between the market value of our common shares and the weighted-average exercise price of the options. As a result, we recognized an obligation of $85 million for the graded vested portion of the options outstanding on June 30, 2004. In the second quarter of 2004, a one-time, non-cash charge of $82 million was included in general and administrative expense, net of $3 million previously expensed in respect of our original stock options.

Following the introduction of the *American Job Creation Act of 2004* in the US, stock options awarded to our US employees between December 1, 2004 and December 1, 2005 did not include a tandem option cash feature. We use the fair-value method to recognize compensation expense associated with these options. The expense is recognized over the vesting period of the options with a corresponding increase to contributed surplus. This resulted in compensation expense in 2005 of $2 million (2004—$0.1 million) which was included in general and administrative expense. In 2005, US tax regulations were modified. As a result, tandem options have been issued to our US employees after December 1, 2005. These options are expensed using the intrinsic-method described above.

We have granted options to purchase common shares to directors, officers and employees. Each option permits the holder to purchase one Nexen common share at the stated exercise price. Options granted prior to February 2001 vest over four years and are exercisable on a cumulative basis over 10 years. Options granted after February 2001 vest over three years and are exercisable on a cumulative basis over five years. At the time of grant, the exercise price equals the market price. The following options have been granted:

	2005		2004		2003	
	Options (thousands)	Weighted Average Exercise Price ($/option)	Options (thousands)	Weighted Average Exercise Price ($/option)	Options (thousands)	Weighted Average Exercise Price ($/option)
Balance at Beginning of Year	16,276	20	18,406	17	18,952	15
Granted	3,392	55	4,224	25	3,753	22
Exercised for Stock	(1,823)	16	(5,902)	15	(3,927)	14
Surrendered for Cash	(2,089)	17	(289)	17	–	–
Forfeited	(441)	22	(163)	17	(372)	16
Balance at End of Year	**15,315**	**28**	**16,276**	**20**	**18,406**	**17**
Options Exercisable at End of Year	8,131	19	8,455	17	10,133	15
Common Shares Reserved for Issuance Under the Stock Option Plan	17,290		19,172		19,576	

The range of exercise prices of options outstanding and exercisable at December 31, 2005 is as follows:

	Outstanding Options			Exercisable Options	
	Number of Options (thousands)	Weighted Average Exercise Price ($/option)	Weighted Average Years to Expiry (years)	Number of Options (thousands)	Weighted Average Exercise Price ($/option)
$5.00 to $9.99	196	9	3	196	9
$10.00 to $14.99	1,198	13	3	1,198	13
$15.00 to $19.99	4,266	18	3	3,992	17
$20.00 to $24.99	3,311	23	3	1,774	22
$25.00 to $29.99	2,974	25	4	971	25
$30.00 to $34.99	38	31	4	–	–
$35.00 to $39.99	–	–	–	–	–
$40.00 to $44.99	2	40	5	–	–
$45.00 to $49.99	14	47	5	–	–
$50.00 to $54.99	2,669	55	5	–	–
$55.00 to $59.99	647	55	5	–	–
Total Options	**15,315**			**8,131**	

In previous periods, we estimated the fair value of stock options issued using the Generalized Black-Scholes option pricing model under the following assumptions:

	2003
Weighted-Average Fair Value ($/option)	10.10
Risk-Free Interest Rate (%)	3.6
Estimated Hold Period Prior to Exercise (years)	3
Volatility in the Price of Nexen's Common Shares (%)	30
Dividends per Common Share ($/share)	0.40

The following shows pro forma net income and earnings per common share had we applied the fair-value method to account for all stock options outstanding that were granted up to December 31, 2002. Stock options granted after that date have been expensed as general and administrative costs.

	2003
Fair Value of Stock Options Granted	25
Less: Fair Value of Stock Options Expensed	(1)
	24
Net Income Attributable to Common Shareholders	
As Reported	578
Pro Forma	554
Earnings Per Common Share ($/share)	
Basic as Reported	2.33
Pro Forma	2.24
Diluted as Reported	2.31
Pro Forma	2.22

(d) Stock appreciation rights

Under our stock appreciation rights (StARs) plan established in 2001, employees are entitled to cash payments equal to the excess of the market price of the common shares over the exercise price of the right. The vesting period and other terms of the plan are similar to the stock option plan. The total rights granted and outstanding at any time cannot exceed 10% of Nexen's total outstanding common shares. At the time of grant, the exercise price equals the market price. The following stock appreciation rights have been granted:

	2005		2004		2003	
	StARs (thousands)	Weighted Average Exercise Price ($/right)	StARs (thousands)	Weighted Average Exercise Price ($/right)	StARs (thousands)	Weighted Average Exercise Price ($/right)
Balance at Beginning of Year	6,436	22	4,809	18	3,625	17
Granted	1,443	55	2,609	25	2,033	22
Exercised for Cash	(1,455)	19	(867)	16	(725)	16
Forfeited	(460)	23	(115)	18	(124)	16
Balance at End of Year	**5,964**	**30**	**6,436**	**22**	**4,809**	**18**
Rights Exercisable at End of Year	2,426	21	2,021	17	990	17

The range of exercise prices of StARs outstanding and exercisable at December 31, 2005 is as follows:

	Outstanding StARs			Exercisable StARs	
	Number of StARs (thousands)	Weighted Average Exercise Price ($/right)	Weighted Average Years to Expiry (years)	Number of StARs (thousands)	Weighted Average Exercise Price ($/right)
$15.00 to $19.99	1,028	16	2	1,024	16
$20.00 to $24.99	1,308	22	3	737	22
$25.00 to $29.99	2,193	25	4	665	25
$30.00 to $34.99	18	33	4	–	–
$35.00 to $39.99	15	37	5	–	–
$40.00 to $44.99	9	41	5	–	–
$45.00 to $49.99	39	48	5	–	–
$50.00 to $54.99	1,353	55	5	–	–
$55.00 to $59.99	1	55	5	–	–
Total StARs	**5,964**			**2,426**	

13. EARNINGS PER COMMON SHARE

Our shareholders approved a split of our issued and outstanding common shares on a two-for-one basis at our annual and special meeting on April 27, 2005. All common share and per common share amounts have been restated to retroactively reflect this share split.

We calculate basic earnings per common share from continuing operations using net income from continuing operations divided by the weighted-average number of common shares outstanding. We calculate basic earnings per common share using net income and the weighted-average number of common shares outstanding. We calculate diluted earnings per common share from continuing operations and diluted earnings per common share in the same manner as basic, except we use the weighted-average number of diluted common shares outstanding in the denominator.

(millions of shares)	2005	2004	2003
Weighted-Average Number of Common Shares Outstanding	260.4	257.3	247.5
Shares Issuable Pursuant to Stock Options	13.4	13.1	12.6
Shares to be Purchased from Proceeds of Stock Options	(7.4)	(9.8)	(10.2)
Weighted-Average Number of Diluted Common Shares Outstanding	**266.4**	**260.6**	**249.9**

In calculating the weighted-average number of diluted common shares outstanding for the year ended December 31, 2005, we excluded 280,708 options (2004—348,200; 2003—5,634,046), because their exercise price was greater than the annual average common share market price in those periods. During the last three years, outstanding stock options were the only potential dilutive instruments.

14. DISCONTINUED OPERATIONS

In the third quarter of 2005, we sold certain Canadian conventional oil and gas properties in southeast Saskatchewan, northwest Saskatchewan, northeast British Columbia and the Alberta foothills. The results of operations of these properties have been presented as discontinued operations. The sales closed in the third quarter of 2005 with net proceeds of $900 million after closing adjustments, and we realized gains of $225 million. These gains are net of losses attributable to pipeline contracts and fixed price gas sales contracts associated with these properties that we have retained, but no longer use in connection with our oil and gas business.

During the fourth quarter of 2004, we concluded production from our Buffalo field, offshore Australia. The results of our operations in Australia have been presented as discontinued operations, as we have no plans to continue operations in the country. Remediation and abandonment activities have been completed, and no gain or loss was recognized.

During the third quarter of 2003, we sold certain non-core conventional light oil properties in southeast Saskatchewan. Net proceeds were $268 million, and there was no gain or loss on the sale.

The results of operations from these properties in Australia and Canada are detailed below and shown as discontinued operations in our Consolidated Statement of Income.

	2005	2004			2003		
	Canada	Canada	Australia	Total	Canada	Australia	Total
Revenues and Other Income							
Net Sales	154	232	75	307	278	64	342
Marketing and Other	–	1	–	1	–	–	–
Gain on Disposition of Assets	225	–	–	–	–	–	–
	379	233	75	308	278	64	342
Expenses							
Operating	27	40	53	93	49	30	79
Depreciation, Depletion, Amortization and Impairment	28	70	9	79	101	22	123
General and Administrative	–	–	–	–	5	–	5
Exploration Expense	1	3	–	3	7	1	8
Income before Income Taxes	323	120	13	133	116	11	127
Current Income Taxes	–	–	–	–	–	(4)	(4)
Future Income Taxes	(129)	50	–	50	58	2	60
Net Income	**452**	**70**	**13**	**83**	**58**	**13**	**71**
Earnings per Common Share ($/share)							
Basic (Note 13)	1.74	0.27	0.05	0.32	0.23	0.05	0.28
Diluted (Note 13)	1.70	0.27	0.05	0.32	0.23	0.05	0.28

Assets and liabilities on the Consolidated Balance Sheet as at December 31, 2004, include the following amounts for discontinued operations:

	Canada	Australia	Total
Cash and Cash Equivalents	–	1	1
Accounts Receivable	28	8	36
Other Current Assets	–	1	1
Property, Plant and Equipment, Net	440	–	440
Accounts Payable and Accrued Liabilities	14	25	39
Asset Retirement Obligations	22	–	22
Future Income Tax Liabilities	108	–	108

There were no assets and liabilities related to discontinued operations as at December 31, 2005.

15. COMMITMENTS, CONTINGENCIES AND GUARANTEES

	2006	2007	2008	2009	2010	Thereafter
Operating Leases	33	33	30	29	26	121
Transportation and Storage Commitments	440	133	97	57	45	116
	473	**166**	**127**	**86**	**71**	**237**

We have a number of lawsuits and claims pending including income tax reassessments (see Note 18), for which we currently cannot determine the ultimate result. We record costs as they are incurred or become determinable. We believe the resolution of these matters would not have a material adverse effect on our liquidity, consolidated financial position or results of operations.

During 2005, total rental expense was $47 million (2004—$45 million; 2003—$49 million).

From time to time, we enter into certain types of contracts that require us to indemnify parties against possible third-party claims, particularly when these contracts relate to divestiture transactions. On occasion, we may provide routine indemnifications. The terms of such obligations vary, and generally, a maximum is not explicitly stated. Because the obligations in these agreements are often not explicitly stated, the overall maximum amount of the obligations cannot be reasonably estimated. Historically, we have not been obligated to make significant payments for these obligations. Our Risk Management Committee actively monitors our exposure to the above risks and obtains insurance coverage to satisfy potential or future claims as necessary. We believe that payments, if any, related to such matters, would not have a material adverse effect on our liquidity, financial condition or results of operations.

16. PENSION AND OTHER POST-RETIREMENT BENEFITS

Nexen has contributory and non-contributory defined benefit and defined contribution pension plans, which together cover substantially all employees. Syncrude has a defined benefit plan for its employees, and we disclose only our share of this plan. Under these defined benefit plans, we provide benefits to retirees based on their length of service and final average earnings. Benefits paid out of Nexen's defined benefit plan are indexed to 75% of the annual rate of inflation less 1%, to a maximum increase of 5%.

On the establishment of Canexus during 2005, the portion of the projected benefit obligation and fair value of plan assets relating to Canexus employees was transferred to Canexus from Nexen, subject to regulatory approval. Canexus' pension and other post retirement benefit amounts have been disclosed separately for 2005.

(a) Defined benefit pension plans

The cost of pension benefits earned by employees is determined using the projected-benefit method prorated on employment services and is expensed as services are rendered. We fund these plans according to federal and provincial government regulations by contributing to trust funds administered by an independent trustee. These funds are invested primarily in equities and bonds.

	2005			2004	
	Nexen	Canexus	Syncrude	Nexen	Syncrude
Change in Projected Benefit Obligation (PBO)					
Beginning of Year	217	–	91	192	79
Service Cost	15	1	4	8	3
Interest Cost	12	1	5	12	5
Plan Participants' Contributions	3	–	1	2	–
Actuarial Loss/(Gain)	33	(2)	11	10	7
Benefits Paid	(8)	–	(3)	(7)	(3)
Transfer to Canexus	(49)	49	–	–	–
End of Year [1]	**223**	**49**	**109**	**217**	**91**
Change in Fair Value of Plan Assets					
Beginning of Year	171	–	50	154	44
Actual Return on Plan Assets	18	–	6	16	5
Employer's Contribution	2	–	4	6	4
Plan Participants' Contributions	3	–	1	2	–
Benefits Paid	(8)	–	(3)	(7)	(3)
Transfer to Canexus	(40)	40	–	–	–
End of Year	**146**	**40**	**58**	**171**	**50**
Reconciliation of Funded Status					
Funded Status [2]	(77)	(9)	(51)	(46)	(41)
Unamortized Transitional Obligation	1	–	–	1	–
Unamortized Prior Service Costs	3	–	–	4	–
Unamortized Net Actuarial Loss	44	9	38	30	30
Pension Liability	**(29)**	**–**	**(13)**	**(11)**	**(11)**
Pension Liability Recognized					
Deferred Charges and Other Assets (Note 10)	–	–	–	13	–
Accounts Payable and Accrued Liabilities	(1)	–	(2)	(1)	(2)
Other Deferred Credits and Liabilities (Note 11)	(28)	–	(11)	(23)	(9)
Pension Liability	**(29)**	**–**	**(13)**	**(11)**	**(11)**
Assumptions (%)					
Accrued Benefit Obligation at December 31					
Discount Rate	5.25	5.25	5.00	6.00	5.75
Long-Term Rate of Employee Compensation Increase	4.00	4.00	4.00	4.00	4.00
Benefit Cost for Year Ended December 31 [3]					
Discount Rate	5.00	5.00	5.00	6.25	6.00
Long-Term Rate of Employee Compensation Increase	4.00	4.00	4.00	4.00	4.00
Long-Term Annual Rate of Return on Plan Assets [4]	7.00	6.50	8.50	7.00	8.50

Notes:

1 The accumulated benefit obligations (the projected benefit obligation excluding future salary increases) of the Nexen and Canexus plans were $161 million and $36 million at December 31, 2005, respectively. Nexen's supplemental pension plan's accumulated benefit obligation was $29 million at December 31, 2005, and Canexus' was nil. Nexen's share of Syncrude's employee pension plan's accumulated benefit obligation was $82 million at December 31, 2005.

2 Includes unfunded obligations for supplemental benefits to the extent that the benefit is limited by statutory guidelines. At December 31, 2005, the PBO for Nexen's supplemental benefits was $43 million (2004—$34 million) and $1 million for Canexus (2004—nil).

3 The assumptions have been used to calculate the recognized expense for Nexen and Canexus. There were no changes to the assumptions between the measurement date and December 31, 2005. Syncrude's measurement date was December 31, 2005.

4 The long-term annual rate of return on plan assets assumption is based on a mix of historical market returns for debt and equity securities.

Net Pension Expense Recognized Under Our Defined Benefit Pension Plans

	2005	2004	2003
Nexen			
Cost of Benefits Earned by Employees	15	8	7
Interest Cost on Benefits Earned	12	12	11
Actual Return on Plan Assets	(18)	(16)	(15)
Actuarial Losses	33	10	14
Pension Expense Before Adjustments for the Long-Term Nature of Employee Future Benefit Costs	42	14	17
Difference Between Actual and Expected Return	8	5	7
Difference Between Actual and Recognized Actuarial Losses	(32)	(10)	(15)
Difference Between Actual and Recognized Past Service Costs	–	1	1
Net Pension Expense	18	10	10
Canexus			
Cost of Benefits Earned by Employees	1	–	–
Interest Cost on Benefits Earned	1	–	–
Actual Return on Plan Assets	–	–	–
Actuarial Gains	(2)	–	–
Pension Expense Before Adjustments for the Long-Term Nature of Employee Future Benefit Costs	–	–	–
Difference Between Actual and Expected Return	(1)	–	–
Difference Between Actual and Recognized Actuarial Gains	2	–	–
Difference Between Actual and Recognized Past Service Costs	–	–	–
Net Pension Expense	1	–	–
Syncrude			
Cost of Benefits Earned by Employees	4	3	3
Interest Cost on Benefits Earned	5	5	4
Actual Return on Plan Assets	(6)	(5)	(7)
Actuarial Losses	11	7	6
Pension Expense Before Adjustments for the Long-Term Nature of Employee Future Benefit Costs	14	10	6
Difference Between Actual and Expected Return	2	1	4
Difference Between Actual and Recognized Actuarial Losses	(8)	(6)	(5)
Difference Between Actual and Recognized Past Service Costs	–	–	–
Net Pension Expense	8	5	5
Total Net Pension Expense	**27**	**15**	**15**

(b) Plan asset allocation at December 31

Our investment goal for the assets in our defined benefit pension plans is to preserve capital and earn a long-term rate of return on assets, net of all management expenses, in excess of the inflation rate. Investment funds are managed by external fund managers based on policies approved by the Board of Directors and Pension Committees of Nexen and Canexus. Nexen's and Canexus' investment strategy is to diversify plan assets between debt and equity securities of Canadian and non-Canadian corporations that are traded on recognized stock exchanges. Allowable and prohibited investment types are also prescribed in Nexen's investment policies.

Syncrude's pension plan is governed and administered separately from ours. Syncrude's investment assets are subject to a similar investment goal, policy and strategy.

(%)	Expected 2006	2005	2004
Nexen			
Equity Securities	60	60	60
Debt Securities	40	40	40
Real Estate	–	–	–
Other	–	–	–
Total	**100**	**100**	**100**
Canexus			
Equity Securities	60	60	–
Debt Securities	40	40	–
Real Estate	–	–	–
Other	–	–	–
Total	**100**	**100**	**–**
Syncrude			
Equity Securities	70	70	70
Debt Securities	30	30	30
Real Estate	–	–	–
Other	–	–	–
Total	**100**	**100**	**100**

(c) Defined contribution pension plans

Under these plans, pension benefits are based on plan contributions. During 2005, Canadian pension expense for these plans was \$4 million (2004—\$4 million; 2003—\$4 million). During 2005, US pension expense for these plans was \$4 million (2004—\$3 million; 2003—\$3 million).

(d) Post-retirement benefits

Nexen provides certain post-retirement benefits, including group life and supplemental health insurance, to eligible employees and their dependents. These costs are fully accrued as compensation in the period employees work; however, these future obligations are not funded. The present value of Nexen employees' future post retirement benefits in 2005 was \$4 million (2004—\$5 million) and \$2 million for Canexus (2004—nil). Nexen's share of post-retirement and post-employment benefits related to Syncrude in 2005 was \$5 million (2004—\$7 million).

(e) Employer funding contributions and benefit payments

Canadian regulators have prescribed funding requirements for our defined benefit plans. Our funding contributions over the last three years have met these requirements and also included additional discretionary contributions permitted by law. For our defined contribution plans, we always match the employee contribution, and no further obligation exists. Our funding contributions for the defined benefit plans are:

	Expected 2006	2005	2004
Defined Benefit Contributions			
Nexen	18	2	6
Canexus	2	–	–
Syncrude	5	4	4
Total Funding Contributions	**25**	**6**	**10**

Our most recent funding valuation was prepared as of August 17, 2005. Our next funding valuation is required by June 30, 2008. Canexus' most recent funding valuation was prepared as of August 17, 2005, and their next funding valuation is required by December 31, 2007. Syncrude's most recent funding valuation was prepared as of December 31, 2003, and their next funding valuation is December 31, 2006.

Our total benefit payments in 2005 were $8 million for Nexen (2004—$7 million) and nil for Canexus (2004—nil). Our share of Syncrude's total benefit payments in 2005 was $3 million (2004—$3 million). Our estimated future payments are as follows:

	Defined Benefit			Other		
	Nexen	Canexus	Syncrude	Nexen	Canexus	Syncrude
2006	8	–	3	1	–	–
2007	9	1	3	1	–	–
2008	9	1	4	2	–	–
2009	10	1	4	2	–	–
2010	11	1	4	2	–	–
2011–2015	66	13	28	14	–	2

17. MARKETING AND OTHER

	2005	2004	2003
Marketing Revenue, Net	847	608	568
Change in Fair Value of Crude Oil Put Options	(196)	56	–
Interest	29	12	9
Foreign Exchange Gains (Losses)	(19)	(13)	6
Gains on Disposition of Assets [1]	4	24	–
Other [2]	37	26	27
Total Marketing and Other	**702**	**713**	**610**

Notes:

1 In 2005, gains on disposition of assets resulted from the sale of minor oil and gas assets by our Nigeria oil and gas business (2004—sale of minor oil and gas assets by our Canadian oil and gas business).

2 In 2005, other includes $2 million (2004—$10 million) of business interruption proceeds received from our insurers. The proceeds result from damage sustained in the Gulf of Mexico during tropical storm Isidore and Hurricane Lili in the third and fourth quarters of 2002.

18. INCOME TAXES

(a) Temporary differences

	2005		2004	
	Future Income Tax Assets	Future Income Tax Liabilities	Future Income Tax Assets	Future Income Tax Liabilities
Property, Plant and Equipment, Net	31	1,785	31	1,852
Tax Losses Carried Forward	370	–	277	–
Deferred Income	–	175	–	171
Recoverable Taxes	9	–	25	–
Total	**410**	**1,960**	**333**	**2,023**

(b) Canadian and foreign income taxes

	2005	2004	2003
Income from Continuing Operations before Income Taxes			
Canadian	(387)	24	(352)
Foreign	1,334	1,003	956
	947	1,027	604
Provision for Income Taxes			
Current			
Canadian	1	6	5
Foreign	338	242	209
	339	248	214
Future			
Canadian	(203)	(3)	(180)
Foreign	103	72	63
	(100)	69	(117)
Total Provision for Income Taxes	**239**	**317**	**97**

The Canadian and foreign components of the provision for income taxes are based on the jurisdiction in which income is taxed. Foreign taxes relate mainly to Yemen, Colombia and the United States and include Yemen cash taxes of $296 million (2004—$227 million; 2003—$201 million).

(c) Reconciliation of effective tax rate to the Canadian federal tax rate

	2005	2004	2003
Income before Income Taxes From Continuing Operations	947	1,027	604
Provision for Income Taxes Computed at the Canadian Statutory Rate	324	354	224
Add (Deduct) the Tax Effect of:			
Royalties and Rentals to Provincial Governments	24	20	20
Resource Allowance and Provincial Tax Rebates	(24)	(29)	(35)
Lower Tax Rates on Foreign Operations	(40)	(22)	(48)
Additional Canadian Tax on Canadian Resource Income	6	7	8
Lower Tax Rates on Capital Gains	(54)	–	–
Federal and Provincial Capital Tax	5	6	4
Revaluation of Future Income Tax Liabilities for Reductions in Statutory Rates	–	(15)	(76)
Other	(2)	(4)	–
Provision for Income Taxes	**239**	**317**	**97**

In 2004 and 2003, the federal and some provincial governments in Canada reduced statutory income tax rates. This reduced our liability and provision for future income taxes by $15 million and $76 million in 2004 and 2003, respectively.

(d) Available unused tax losses and tax contingencies

At December 31, 2005 and 2004, we had unused tax losses totalling $965 million and $702 million, respectively, mostly from our UK operations.

Nexen's income tax filings are subject to audit by taxation authorities. There are audits in progress and items under review, some of which may increase our tax liability. In addition, we have filed notices of objection with respect to certain issues. While the results of these items cannot be ascertained at this time, we believe we have an adequate provision for income taxes based on available information.

At the time of acquisition, Wascana had outstanding taxation issues in dispute from prior taxation years. Wascana disagreed with issues raised and has filed notices of objection. The value of the tax pools acquired at the time of acquisition reflected our evaluation of the potential impact of these issues.

19. CASH FLOWS

(a) Charges and credits to income not involving cash

	2005	2004	2003
Depreciation, Depletion, Amortization and Impairment	1,052	674	914
Stock Based Compensation	411	74	4
Gains on Disposition of Assets	(4)	(24)	–
Future Income Taxes	(100)	69	(117)
Change in Fair Value of Crude Oil Put Options	196	(56)	–
Non-Cash Items included in Discontinued Operations	(325)	132	191
Unamortized Issue Costs on Preferred Securities Redemption	–	11	28
Gain on Dilution of Interest in Chemicals Business	(193)	–	–
Net Income Attributable to Non-Controlling Interests	8	–	–
Other	24	26	4
Total	**1,069**	**906**	**1,024**

(b) Changes in non-cash working capital

	2005	2004	2003
Accounts Receivable	(1,078)	(454)	(488)
Inventories and Supplies	(163)	(106)	(45)
Other Current Assets	(10)	44	(59)
Accounts Payable and Accrued Liabilities	982	650	242
Other	20	(12)	12
Total	**(249)**	**122**	**(338)**
Relating to:			
Operating Activities	(195)	(122)	(320)
Investing Activities	(54)	244	(18)
Total	**(249)**	**122**	**(338)**

(c) Other cash flow information

	2005	2004	2003
Interest Paid	237	190	197
Income Taxes Paid	325	249	211

In 2004, other operating activity cash outflows include $144 million for the purchase of crude oil put options.

20. OPERATING SEGMENTS AND RELATED INFORMATION

Nexen has the following operating segments in various industries and geographic locations:

Oil and Gas: We explore for, develop and produce crude oil, natural gas and related products around the world. We manage our operations to reflect differences in the regulatory environments and risk factors for each country. Our core operations are onshore in Yemen and Canada, and offshore in the US Gulf of Mexico and the UK North Sea. Our other operations are primarily in West Africa and Colombia. Oil and gas also includes our marketing operations. Marketing sells our own crude oil and natural gas, markets third-party crude oil and natural gas and engages in energy trading.

Syncrude: We own 7.23% of the Syncrude Joint Venture, which develops and produces synthetic crude oil from mining bitumen in the oil sands in northern Alberta.

Chemicals: Through our investment in Canexus, we manufacture, market and distribute industrial chemicals, principally sodium chlorate, chlorine, acid and caustic soda. We produce sodium chlorate at four facilities in Canada and one in Brazil. We produce chlorine, caustic soda and muriatic acid at chlor-alkali facilities in Canada and Brazil.

The accounting policies of our operating segments are the same as those described in Note 1. Net income of our operating segments excludes interest income, interest expense, unallocated corporate expenses and foreign exchange gains and losses with the exception of Chemicals. Identifiable assets are those used in the operations of the segments.

2005 Operating and Geographic Segments

	Oil and Gas						Syncrude [1]	Chemicals	Corporate and Other	Total
(Cdn$ millions)	Yemen	Canada [2]	US	UK	Other Countries [3]	Marketing				
Net Sales [4]	1,377	455	792	366	119	28	397	398 [5]	–	3,932
Marketing and Other	8	3	2	16	4	847	–	15	(193) [6]	702
Gain on Dilution of Interest in Chemicals Business	–	–	–	–	–	–	–	193	–	193
	1,385	458	794	382	123	875	397	606	(193)	4,827
Less: Expenses										
Operating	150	121	96	95	12	30	152	237	–	893
Depreciation, Depletion, Amortization and Impairment	354	140	234	210	13	11	17	51 [7]	22	1,052
Transportation and Other	6	23	1	–	2	641	21	40	62	796
General and Administrative [8]	42	105	84	8	97	89	1	45	321	792
Exploration	12	23	100	51	64 [9]	–	–	–	–	250
Interest	–	–	–	–	–	–	–	3	94	97
Income (Loss) from Continuing Operations before Income Taxes	821	46	279	18	(65)	104	206	230	(692)	947
Less: Provision for (Recovery of) Income Taxes [10]	285	14	99	7	(12)	41	60	15	(270)	239
Net Income (Loss) from Continuing Operations	536	32	180	11	(53)	63	146	215	(422)	708
Less: Non-Controlling Interests	–	–	–	–	–	–	–	8	–	8
Add: Net Income from Discontinued Operations	–	452	–	–	–	–	–	–	–	452
Net Income (Loss)	**536**	**484**	**180**	**11**	**(53)**	**63**	**146**	**207**	**(422)**	**1,152**
Identifiable Assets	**635**	**2,449**	**1,433**	**4,775**	**183**	**3,165** [11]	**1,135**	**482**	**333**	**14,590**
Capital Expenditures										
Development and Other	236	947	148	566	14	16	197	14	24	2,162
Exploration	41	90	211	59	55	–	–	–	–	456
Proved Property Acquisitions	–	17	3	–	–	–	–	–	–	20
Total Capital Expenditures	**277**	**1,054**	**362**	**625**	**69**	**16**	**197**	**14**	**24**	**2,638**
Property, Plant and Equipment										
Cost	2,243	3,631	2,437	4,013	249	177	1,240	827	245	15,062
Less: Accumulated DD&A	1,841	1,311	1,159	216	119	72	171	456	123	5,468
Net Book Value [4]	**402**	**2,320**	**1,278**	**3,797**	**130**	**105**	**1,069**	**371**	**122**	**9,594**
Goodwill										
Cost	–	–	–	325	–	63	–	–	–	388
Less: Accumulated DD&A	–	–	–	–	–	24	–	–	–	24
Net Book Value	**–**	**–**	**–**	**325**	**–**	**39**	**–**	**–**	**–**	**364**

Notes:

1 Syncrude is considered a mining operation for US reporting purposes. PP&E at December 31, 2005 includes mineral rights of $6 million.

2 During the third quarter of 2005, we concluded the sale of certain Canadian conventional oil and gas properties. The results of these properties are shown as discontinued operations (see Note 14).

3 Includes results of operations from producing activities in Nigeria and Colombia.

4 Net sales made from all segments originating in Canada: 1,014
PP&E located in Canada: 3,899

5 Net sales for our chemicals operations include:

Canada	132
United States	198
Brazil	68
Total	398

6 Includes interest income of $29 million, foreign exchange losses of $19 million, decrease in the fair value of crude oil put options of $196 million and decrease in the fair value of foreign currency call options of $7 million.

7 Includes impairment charge of $12 million related to the closure of our sodium chlorate plant in Amherstburg, Ontario.

8 Includes stock-based compensation expense of $490 million.

9 Includes exploration activities primarily in Nigeria, Colombia and Equatorial Guinea.

10 The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.

11 Approximately 86% of Marketing's identifiable assets are accounts receivable and inventories.

2004 Operating and Geographic Segments

(Cdn$ millions)	Oil and Gas						Syncrude [1]	Chemicals	Corporate and Other	Total
	Yemen	Canada	US	UK [2]	Other Countries [3]	Marketing				
Net Sales [4]	921	390	811	36	73	14	321	378 [5]	–	2,944
Marketing and Other	5	27	11	–	2	608	–	5	55 [6]	713
	926	417	822	36	75	622	321	383	55	3,657
Less: Expenses										
Operating	109	116	106	6	7	16	125	237	–	722
Depreciation, Depletion, Amortization and Impairment	169	128	258	18	18	10	18	37	18	674
Transportation and Other	5	15	–	–	–	451	12	41	25	549
General and Administrative	4	42	30	–	47	58	1	28	89	299
Exploration	2	18	138	3	82 [7]	–	–	–	–	243
Interest	–	–	–	–	–	–	–	–	143	143
Income (Loss) from Continuing Operations before Income Taxes	637	98	290	9	(79)	87	165	40	(220)	1,027
Less: Provision for (Recovery of) Income Taxes [8]	222	28	104	4	1	28	47	13	(130)	317
Net Income (Loss) from Continuing Operations	415	70	186	5	(80)	59	118	27	(90)	710
Add: Net Income from Discontinued Operations [9]	–	70	–	–	13	–	–	–	–	83
Net Income (Loss)	**415**	**140**	**186**	**5**	**(67)**	**59**	**118**	**27**	**(90)**	**793**
Identifiable Assets	**564**	**1,979**	**1,359**	**4,446**	**218**	**2,030** [10]	**912**	**497**	**378**	**12,383**
Capital Expenditures										
Development and Other	267	491	267	53	24	4	214	58	33	1,411
Exploration	19	46	133	4	64	–	–	–	–	266
Proved Property Acquisitions	–	4	–	–	–	–	–	–	–	4
Total Capital Expenditures	**286**	**541**	**400**	**57**	**88**	**4**	**214**	**58**	**33**	**1,681**
Property, Plant and Equipment										
Cost	2,038	2,603	2,249	3,499	535	157	1,030	815	201	13,127
Less: Accumulated DD&A	1,550	1,195	1,037	16	408	64	155	409	90	4,924
Net Book Value [4]	**488**	**1,408** [11]	**1,212**	**3,483**	**127**	**93**	**875**	**406**	**111**	**8,203**
Goodwill										
Cost	–	–	–	339	–	60	–	–	–	399
Less: Accumulated DD&A	–	–	–	–	–	24	–	–	–	24
Net Book Value	**–**	**–**	**–**	**339**	**–**	**36**	**–**	**–**	**–**	**375**

Notes:

1 Syncrude is considered a mining operation for US reporting purposes. PP&E at December 31, 2004 includes mineral rights of $6 million.

2 On December 1, 2004 we acquired EnCana (UK) Limited (see Note 3).

3 Includes results of operations from producing activities in Nigeria, Colombia, and Australia.

4 Net sales made from all segments originating in Canada: 1,242
PP&E located in Canada: 3,198

5 Net sales for our chemicals operations include:

Canada	135
United States	184
Brazil	59
Total	378

6 Includes interest income of $12 million, foreign exchange losses of $13 million and unrealized mark-to-market gains on crude oil put options of $56 million.

7 Includes exploration activities primarily in Nigeria and Colombia.

8 The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.

9 In the fourth quarter of 2004, we concluded production activities in Australia. During the third quarter of 2005, we concluded the sale of certain Canadian conventional oil and gas properties. The combined results of these dispositions are shown as discontinued operations (see Note 14).

10 Approximately 81% of Marketing's identifiable assets are accounts receivable and inventories.

11 Excludes PP&E costs of $860 million and accumulated DD&A of $420 million relating to the Canadian properties disposed of during 2005 (see Note 14).

2003 Operating and Geographic Segments

(Cdn$ millions)	Oil and Gas: Yemen	Oil and Gas: Canada	Oil and Gas: US	Oil and Gas: Other Countries [2]	Oil and Gas: Marketing [3]	Syncrude [1]	Chemicals	Corporate and Other	Total
Net Sales [4]	827	397	707	65	21	240	375 [5]	–	2,632
Marketing and Other	6	5	14	–	568	–	2	15 [6]	610
	833	402	721	65	589	240	377	15	3,242
Less: Expenses									
Operating	92	110	86	15	22	123	240	–	688
Depreciation, Depletion, Amortization and Impairment	168	409 [7]	207	38	15	14	46	17	914
Transportation and Other	5	4	–	–	398	11	42	29	489
General and Administrative	5	22	13	20	43	1	21	60	185
Exploration	17	28	89	59 [8]	–	–	–	–	193
Interest	–	–	–	–	–	–	–	169	169
Income (Loss) from Continuing Operations before Income Taxes	546	(171)	326	(67)	111	91	28	(260)	604
Less: Provision for (Recovery of) Income Taxes [9]	191	(140)	115	(1)	39	25	10	(142)	97
Net Income (Loss) from Continuing Operations	355	(31)	211	(66)	72	66	18	(118)	507
Add: Net Income from Discontinued Operations	–	58 [10]	–	13 [11]	–	–	–	–	71
Net Income (Loss)	**355**	**27**	**211**	**(53)**	**72**	**66**	**18**	**(118)**	**578**
Identifiable Assets	**574**	**2,176**	**1,446**	**197**	**1,518** [12]	**719**	**475**	**612**	**7,717**
Capital Expenditures									
Development and Other	219	259	249	25	1	195	24	29	1,001
Exploration	34	51	147	97	–	–	–	–	329
Proved Property Acquisitions	–	–	164 [13]	–	–	–	–	–	164
Total Capital Expenditures	**253**	**310**	**560**	**122**	**1**	**195**	**24**	**29**	**1,494**
Property, Plant and Equipment									
Cost	1,898	2,169	2,153	534	158	821	774	168	8,675
Less: Accumulated DD&A	1,497	1,106	887	410	57	144	381	71	4,553
Net Book Value [4]	**401**	**1,063** [14]	**1,266**	**124**	**101**	**677**	**393**	**97**	**4,122**
Goodwill									
Cost	–	–	–	–	60	–	–	–	60
Less: Accumulated DD&A	–	–	–	–	24	–	–	–	24
Net Book Value	**–**	**–**	**–**	**–**	**36**	**–**	**–**	**–**	**36**

Notes:

1 Syncrude is considered a mining operation for US reporting purposes. PP&E at December 31, 2003 includes mineral rights of $6 million.

2 Includes results of operations from producing activities in Nigeria, Colombia and Australia.

3 Includes results of operations from a natural gas-fired generating facility in Alberta.

4 Net sales made from all segments originating in Canada: 1,218
PP&E located in Canada: 2,566

5 Net sales for our chemicals operations include:

Canada	142
United States	179
Brazil	54
Total	375

6 Includes interest income of $9 million and foreign exchange gains of $6 million.

7 Includes impairment charge of $269 million (see Note 6).

8 Includes exploration activities primarily in Nigeria, Colombia, Brazil and Equatorial Guinea.

9 The provision for (recovery of) income taxes for foreign locations is based on in-country taxes on foreign income. For oil and gas locations with no operating activities, the provision is based on the tax jurisdiction of the entity performing the activity.

10 In August 2003, we sold non-core conventional light oil assets in southeast Saskatchewan for net proceeds of $268 million. No gain or loss was recognized on the sale. During the third quarter of 2005, we concluded the sale of certain Canadian conventional oil and gas properties. The combined results of these dispositions are shown as discontinued operations (see Note 14).

11 In the fourth quarter of 2004, we concluded production activities in Australia. These results are shown as discontinued operations (see Note 14).

12 Approximately 80% of Marketing's identifiable assets are accounts receivable and inventories.

13 On March 27, 2003, we acquired the residual 40% interest in Aspen in the Gulf of Mexico for US$109 million.

14 Excludes PP&E costs of $782 million and accumulated DD&A of $354 million relating to the Canadian properties disposed of during 2005 (see Note 14).

21. DIFFERENCES BETWEEN CANADIAN AND US GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Consolidated Financial Statements have been prepared in accordance with Canadian GAAP. US GAAP Consolidated Financial Statements and summaries of differences from Canadian GAAP are as follows:

Consolidated Statement of Income—US GAAP For the Three Years ended December 31, 2005

(Cdn$ millions, except per share amounts)	2005	2004	2003
Revenues and Other Income			
Net Sales	3,932	2,944	2,632
Marketing and Other (ii); (ix); (x)	687	696	623
Gain on Dilution of Interest in Chemicals Business	193	–	–
	4,812	3,640	3,255
Expenses			
Operating (iv)	903	731	694
Depreciation, Depletion, Amortization and Impairment (i)	1,081	716	1,027
Transportation and Other (ix)	792	524	489
General and Administrative (viii)	792	263	185
Exploration	250	243	193
Interest	97	143	169
	3,915	2,620	2,757
Income from Continuing Operations before Income Taxes	897	1,020	498
Provision for Income Taxes			
Current	339	248	214
Deferred (i) – (x)	(108)	67	(135)
	231	315	79
Net Income from Continuing Operations before Non-Controlling Interests	666	705	419
Net Income Attributable to Non-Controlling Interests	8	–	–
Net Income from Continuing Operations before Cumulative Effect of Changes in Accounting Principles	658	705	419
Net Income from Discontinued Operations (i)	452	83	49
Cumulative Effect of Changes in Accounting Principles, Net of Income Taxes (vii); (x)	–	–	(48)
Net Income—US GAAP [1]	**1,110**	**788**	**420**
Earnings Per Common Share ($/share)			
Basic (Note 13)			
Net Income from Continuing Operations	2.52	2.74	1.69
Net Income from Discontinued Operations	1.74	0.32	0.20
Cumulative Effect of Changes in Accounting Principles	–	–	(0.19)
	4.26	3.06	1.70
Diluted (Note 13)			
Net Income from Continuing Operations	2.47	2.71	1.68
Net Income from Discontinued Operations	1.70	0.32	0.19
Cumulative Effect of Changes in Accounting Principles	–	–	(0.19)
	4.17	3.03	1.68

Note:

1 Reconciliation of Canadian and US GAAP Net Income

(Cdn$ millions)	2005	2004	2003
Net Income—Canadian GAAP	1,152	793	578
Impact of US Principles, Net of Income Taxes:			
Fair Value of Preferred Securities (x)	–	4	7
Depreciation, Depletion, Amortization and Impairment (i); (vii)	(29)	(42)	(92)
Stock Based Compensation Included in Retained Earnings (viii)	–	36	–
Loss on Disposition (i)	–	–	(22)
Other (ii); (iv)	(13)	(3)	(3)
Cumulative Effect of Changes in Accounting Principles (vii); (x)	–	–	(48)
Net Income—US GAAP	**1,110**	**788**	**420**

Consolidated Balance Sheet—US GAAP

(Cdn$ millions, except share amounts)	December 31, 2005	December 31, 2004
ASSETS		
Current Assets		
Cash and Cash Equivalents	48	73
Restricted Cash	70	–
Accounts Receivable (ii)	3,151	2,106
Inventories and Supplies	504	351
Assets of Discontinued Operations	–	38
Other	51	41
Total Current Assets	3,824	2,609
Property, Plant and Equipment		
Net of Accumulated Depreciation, Depletion, Amortization and Impairment of $5,861 (December 31, 2004—$5,290) (i); (iv); (vii)	9,550	8,198
Goodwill	364	375
Deferred Income Tax Assets	410	333
Deferred Charges and Other Assets (v)	345	384
Assets of Discontinued Operations	–	440
TOTAL ASSETS	**14,493**	**12,339**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-Term Borrowings	–	100
Accounts Payable and Accrued Liabilities (ii)	3,745	2,377
Accrued Interest Payable	55	34
Dividends Payable	13	13
Liabilities of Discontinued Operations	–	39
Total Current Liabilities	3,813	2,563
Long-Term Debt (v)	3,630	4,214
Deferred Income Tax Liabilities (i) – (x)	1,906	1,993
Asset Retirement Obligations (vii)	590	399
Deferred Credits and Other Liabilities (vi)	505	148
Liabilities of Discontinued Operations	–	130
Non-Controlling Interests	88	–
Shareholders' Equity		
Common Shares, no par value		
Authorized: Unlimited		
Outstanding: 2005—261,140,571 shares		
2004—258,399,166 shares	732	637
Contributed Surplus	2	–
Retained Earnings (i) – (x)	3,418	2,360
Accumulated Other Comprehensive Income (ii); (iii); (vi)	(191)	(105)
Total Shareholders' Equity	3,961	2,892
Commitments, Contingencies and Guarantees		
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**14,493**	**12,339**

Consolidated Statement of Comprehensive Income—US GAAP For the Three Years ended December 31, 2005

(Cdn$ millions)	2005	2004	2003
Net Income—US GAAP	1,110	788	420
Other Comprehensive Income, Net of Income Taxes:			
Translation Adjustment (iii)	(56)	(72)	(127)
Unrealized Mark-to-Market Gain (Loss) (ii)	(20)	11	(7)
Minimum Unfunded Pension Liability (vi)	(10)	(1)	(1)
Comprehensive Income	**1,024**	**726**	**285**

Consolidated Statement of Cash Flows

Under US GAAP, geological and geophysical costs in 2003 of $62 million included in investing activities would be reported in operating activities. See Note 1(u) to our Consolidated Financial Statements.

Notes to the Consolidated US GAAP Financial Statements:

i. Under US GAAP, the liability method of accounting for income taxes was adopted in 1993. In Canada, the liability method was adopted in 2000. In 1997, we acquired certain oil and gas assets, and the amount paid for these assets differed from the tax basis acquired. Under US principles, this difference was recorded as a deferred tax liability with an increase to PP&E rather than a charge to retained earnings. As a result:

- additional depreciation, depletion, amortization and impairment of $29 million (2004—$42 million; 2003—$92 million) was included in net income; and
- PP&E is higher under US GAAP at December 31, 2004 by $29 million.

During the third quarter of 2003, some of these assets were sold as described in Note 14. With the carrying value of these assets higher under US GAAP, the sale resulted in a loss on disposition of $22 million, net of income taxes of $10 million. This loss was included in our 2003 net income from discontinued operations disclosed on the Consolidated Statement of Income—US GAAP.

Included in depreciation, depletion, amortization and impairment expense for 2003 is an impairment charge of $315 million. The amount is higher under US GAAP as we have higher US GAAP carrying values for the assets impaired resulting from differences in adopting the liability method of accounting for income taxes as previously described.

ii. Under US GAAP, all derivative instruments are recognized on the balance sheet as either an asset or a liability measured at fair value. Changes in the fair value of derivatives are recognized in earnings unless specific hedge criteria are met.

Cash flow hedges

Changes in the fair value of derivatives that are designated as cash flow hedges are recognized in net income in the same period as the hedged item. Any fair value change in a derivative before that period is recognized on the balance sheet. The effective portion of that change is recognized in other comprehensive income with any ineffectiveness recognized in net income.

Future sale of oil and gas production: Included in accounts payable at December 31, 2003, was a $3 million loss on forward contracts we used to hedge commodity price risk on the future sale of a portion of our production from the Aspen field. These contracts expired in March 2004. Losses ($2 million, net of income taxes), that were deferred in accumulated other comprehensive income (AOCI) at December 31, 2003, were recognized in net sales in 2004.

Future sale of gas inventory: Included in accounts payable at December 31, 2003, was $11 million of losses on futures and basis swap contracts we used to hedge commodity price risk on the future sale of our gas inventory. These contracts effectively lock-in profits on our stored gas volumes. Losses of $8 million ($5 million, net of income taxes) related to the effective portion and deferred in AOCI at December 31, 2003, were recognized in marketing and other in 2004. Additionally, losses of $3 million ($2 million, net of income taxes), related to the ineffective portion, were recognized in marketing and other under US GAAP in 2003. Under Canadian GAAP, the ineffective portion was recognized in net income in 2004.

Included in accounts receivable at December 31, 2004, were $6 million of gains on futures contracts and swaps we used to hedge commodity price risk on the future sale of our gas inventory as described in Note 7. These contracts effectively lock-in profits on our stored gas volumes. Gains of $6 million ($4 million, net of income taxes) related to the effective portion and deferred in AOCI at December 31, 2004, were recognized in marketing and other during the first quarter of 2005.

At December 31, 2005, losses of $35 million were included in accounts payable with respect to futures contracts and swaps we used to hedge commodity price risk on the future sale of our gas inventory as described in Note 7. Losses of $24 million ($16 million, net of income taxes) related to the effective portion have been deferred in AOCI until the underlying gas inventory is sold. These losses will be reclassified to marketing and other as the contracts settle over the next 12 months. The ineffective portion of the losses of $11 million ($7 million, net of income taxes) was recognized in net income during the year.

Fair value hedges

Both the derivative instrument and the underlying commitment are recognized on the balance sheet at their fair value. The change in fair value of both are reflected in net income. At December 31, 2005, we had no fair value hedges in place.

iii. Under US GAAP, exchange gains and losses arising from the translation of our net investment in self-sustaining foreign operations are included in comprehensive income. Additionally, exchange gains and losses, net of income taxes, from the translation of our US-dollar long-term debt designated as a hedge of our foreign net investment are included in comprehensive income. Cumulative amounts are included in AOCI in the Consolidated Balance Sheet—US GAAP.

iv. Under Canadian GAAP, we defer certain development costs and all pre-operating revenues and costs to PP&E. Under US GAAP, these costs have been included in operating expenses. As a result:

- operating expenses include pre-operating costs of $10 million ($6 million, net of income taxes) (2004—$9 million ($6 million net of income taxes); 2003—$4 million ($2 million, net of income taxes)); and
- PP&E is lower under US GAAP by $25 million (December 31, 2004—$15 million).

v. Under US GAAP, discounts on long-term debt are classified as a reduction of long-term debt rather than as deferred charges and other assets. Discounts of $57 million (December 31, 2004—$45 million) have been included in long-term debt.

vi. Under US GAAP, the amount by which our accrued pension cost is less than the unfunded accumulated benefit obligation is included in AOCI and accrued pension liabilities. As a result, deferred credits and other liabilities are higher by $26 million (2004—$6 million) and deferred charges and other assets are higher by $4 million (2004—nil). In 2005, AOCI decreased by $10 million, net of $6 million of income taxes.

vii. On January 1, 2003, we adopted FASB Statement No. 143, *Accounting for Asset Retirement Obligations* (FAS 143) for US GAAP reporting purposes. We adopted the equivalent Canadian standard for asset retirement obligations on January 1, 2004. These standards are consistent, except for the adoption date, which resulted in our PP&E under US GAAP being lower by $19 million.

This change in accounting policy has been reported as a cumulative effect adjustment in the Consolidated Statement of Income—US GAAP as a loss of $37 million, net of income taxes of $25 million, on January 1, 2003.

viii. As described in Note 12(c), our existing stock option plan was modified to a tandem option plan in 2004. An obligation of $85 million was recognized for these tandem options. This resulted in a one-time, non-cash charge to net income of $54 million, net of tax in the second quarter of 2004. Under US principles, the modification of our stock option plan is accounted for by providing us with credit for the proforma expense previously disclosed for the stock options modified. The related proforma expense was $36 million, which is accounted for as an adjustment to retained earnings with a corresponding decrease to our one-time charge to net income.

ix. Under US GAAP, gains and losses on the disposition of assets are shown as other expense. Gains of $4 million (2004—$24 million; 2003—$nil) were reclassed from marketing and other to transportation and other.

x. In May 2003, the FASB issued Statement No. 150, *Accounting for Certain Instruments with Characteristics of Both Liabilities and Equity* that requires certain financial instruments, including our preferred securities, to be valued at fair value with changes in fair value recognized through net income.

(Cdn$ millions)	Gain (Loss)	Tax	Net Gain (Loss)
Fair Value Change up to June 30, 2003 [2]	(16)	5	(11)
Fair Value Change from July 1, 2003 to December 31, 2003 [1]	12	(5)	7
Fair Value Change from January 1, 2004 to February 9, 2004 [1,3]	4	–	4

Notes:
1 Included in marketing and other.
2 Reported as cumulative effect of a change in accounting principle.
3 Redemption date of preferred securities.

New Accounting Pronouncements

In November 2004, the Financial Accounting Standards Board (FASB) issued Statement 151, *Inventory Costs*. This statement amends ARB 43 to clarify that:

- abnormal amounts of idle facility expense, freight, handling costs and wasted material (spoilage) should be recognized as current-period charges; and
- requires the allocation of fixed production overhead to inventory based on the normal capacity of the production facilities.

The provisions of this statement are effective for inventory costs incurred during fiscal years beginning after June 15, 2005. We do not expect the adoption of this statement will have any material impact on our results of operations or financial position.

In December 2004, the FASB issued Statement 123(R), *Share-Based Payments*. This statement revises Statement 123, *Accounting for Stock-Based Compensation*, and supersedes APB Opinion 25, *Accounting for Stock Issued to Employees*. Statement 123(R) requires all stock-based awards issued to employees to be measured at fair value and to be expensed in the income statement. This statement is effective for fiscal years beginning after June 15, 2005.

We are currently expensing stock-based awards issued to employees using the fair-value method for equity based awards and the intrinsic method for liability-based awards. Adoption of this standard will change our expense under US GAAP for tandem options and stock appreciation rights as these awards will be measured using the fair-value method rather than the intrinsic method. Upon implementing the new rules, we expect to record an expense for US GAAP purposes of $3 million ($2 million net of income taxes) in 2006, reflecting the cumulative effect of the change in accounting policy.

In December 2004, the FASB issued Statement 153, *Exchanges of Nonmonetary Assets*, an amendment of APB Opinion 29, *Accounting for Nonmonetary Transactions*. This amendment eliminates the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. Under Statement 153, if a nonmonetary exchange of similar productive assets meets a commercial-substance criterion and fair value is determinable, the transaction must be accounted for at fair value resulting in recognition of any gain or loss. This statement is effective for nonmonetary transactions in fiscal periods that begin after June 15, 2005. The adoption of this statement will not have any material impact on our results of operations or financial position.

In March 2005, the FASB issued Financial Interpretation 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47). FIN 47 clarifies that the term conditional asset retirement obligation as used in FASB Statement No. 143, *Accounting for Asset Retirement Obligations*, refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. Thus, the timing and/or method of settlement may be conditional on a future event. Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. FIN 47 is effective no later than the end of fiscal years ending after December 15, 2005. The adoption of this statement has not had a material impact on our results of operations or financial position.

In March 2005, the Emerging Issues Task Force (EITF) reached a consensus on Issue No. 04-6, *Accounting for Stripping Costs Incurred during Production in the Mining Industry*. In the mining industry, companies may be required to remove overburden and other mine waste materials to access mineral deposits. The EITF concluded that the costs of removing overburden and waste materials, often referred to as "stripping costs", incurred during the production phase of a mine are variable production costs that should be included in the costs of the inventory produced during the period that the stripping costs are incurred. Issue No. 04-6 is effective for the first reporting period in fiscal years beginning after December 15, 2005, with early adoption permitted. We do not expect the adoption of this statement will have a material impact on our results of operations or financial position.

In June 2005, the FASB issued Statement 154, *Accounting Changes and Error Corrections* which replaces APB Opinion 20 and FASB Statement 3. Statement 154 changes the requirements for the accounting and reporting of a change in accounting principle. Opinion 20 previously required that most voluntary changes in accounting principles be recognized by including the cumulative effect of the new accounting principle in net income of the period of the change. In the absence of explicit transition provisions provided for in new or existing accounting pronouncements, Statement 154 now requires retrospective application of changes in accounting principle to prior period financial statements, unless it is impracticable to do so. The Statement is effective for fiscal years beginning after December 15, 2005. We do not expect the adoption of this statement will have a material impact on our results of operations or financial position.

In September 2005, the EITF reached a consensus on Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*. This issue addresses the question of when it is appropriate to measure purchase and sales of inventory at fair value and record them in cost of sales and revenues and when they should be recorded as exchanges measured at the book value of the item sold. The EITF concluded that purchases and sales of inventory with the same counterparty that are entered into in contemplation of one another should be combined and recorded as exchanges measured at the book value of the item sold. The consensus should be applied to new arrangements entered into, and modifications or renewals of existing agreements, beginning with the second quarter of 2006. We do not expect the adoption of this statement will have a material impact on our results of operations or financial position.

SUPPLEMENTARY DATA (UNAUDITED)

Quarterly Financial Data in Accordance with Canadian and US GAAP

	Quarter Ended							
	March 31		June 30		September 30		December 31	
(Cdn$ millions)	2005	2004	2005	2004	2005	2004	2005	2004
Net Sales [1]	856	664	909	697	1,094	778	1,073	805
Operating Profit is Comprised of: [1, 2, 3, 4, 5]								
Oil and Gas	282	243	250	199	173	296	498	304
Syncrude	19	40	59	40	78	52	50	33
Chemicals	7	10	(2)	6	215	11	10	13
	308	**293**	**307**	**245**	**466**	**359**	**558**	**350**
Net Income from Continuing Operations—Canadian GAAP [6]	**19**	**167**	**170**	**117**	**211**	**200**	**300**	**226**
US GAAP Adjustments	(11)	(20)	(12)	39	(15)	(12)	(4)	(12)
Net Income from Continuing Operations—US GAAP	**8**	**147**	**158**	**156**	**196**	**188**	**296**	**214**
Net Income—Canadian GAAP	**37**	**184**	**200**	**143**	**615**	**220**	**300**	**246**
US GAAP Adjustments	(11)	(20)	(12)	39	(15)	(12)	(4)	(12)
Net Income—US GAAP	**26**	**164**	**188**	**182**	**600**	**208**	**296**	**234**
Earnings per Common Share from Continuing Operations ($/share)								
Canadian GAAP—Basic	0.08	0.66	0.65	0.45	0.81	0.77	1.15	0.87
Canadian GAAP—Diluted	0.08	0.66	0.64	0.44	0.79	0.76	1.12	0.86
US GAAP—Basic	0.03	0.58	0.61	0.61	0.75	0.73	1.13	0.82
US GAAP—Diluted	0.03	0.57	0.60	0.60	0.73	0.72	1.11	0.82
Earnings per Common Share ($/share)								
Canadian GAAP—Basic	0.15	0.73	0.77	0.55	2.36	0.85	1.15	0.95
Canadian GAAP—Diluted	0.15	0.72	0.76	0.54	2.30	0.84	1.12	0.94
US GAAP—Basic	0.10	0.64	0.72	0.71	2.31	0.81	1.13	0.90
US GAAP—Diluted	0.10	0.63	0.71	0.70	2.25	0.80	1.11	0.89
Dividends Declared [7]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Common Share Prices ($/share)								
Toronto Stock Exchange—High	35.50	26.68	39.85	28.25	60.67	26.85	59.54	29.33
Toronto Stock Exchange—Low	23.55	22.50	29.53	23.40	40.25	22.17	43.77	24.09
New York Stock Exchange—High (US$)	29.18	20.31	32.32	21.15	51.73	21.07	51.69	23.28
New York Stock Exchange—Low (US$)	19.44	17.05	23.28	17.25	31.95	16.94	36.80	19.60

Notes:

1 Excludes results of certain Canadian conventional oil and gas properties sold in the third quarter of 2005 in southeast Saskatchewan, northwest Saskatchewan, northeast British Columbia and the Alberta foothills, the 2003 sale of non-core conventional light oil assets in southeast Saskatchewan and conclusion of production from our Buffalo field, offshore Australia in 2004. These results are shown as discontinued operations (see Note 14 to the Consolidated Financial Statements).

2 Plant turnarounds and coker maintenance at Syncrude in the fourth quarter of 2004 and first quarter of 2005 increased operating costs and temporarily reduced production volumes.

3 In 2004, a gain of $24 million was recorded on the sale of minor assets by our Canadian oil and gas business.

4 Chemicals operating profit includes a dilution gain of $193 million in the third quarter of 2005 as the result of the Canexus initial public offering.

5 Operating profit is defined as income (loss) from continuing operations before income taxes.

6 Includes the impact of changes in accounting policies as described in Note 1(u) to the Consolidated Financial Statements.

7 In February 2006, the Board of Directors declared a regular quarterly dividend of $0.05 per common share, payable April 1, 2006, to shareholders of record on March 10, 2006.

8 At December 31, 2005, there were 1,294 registered holders of common shares and 261,140,571 common shares outstanding.

OIL AND GAS PRODUCING ACTIVITIES AND SYNCRUDE OPERATIONS (UNAUDITED)

The following oil and gas information is provided in accordance with the FASB Statement No. 69 *Disclosures about Oil and Gas Producing Activities*. It also includes information relating to our interest in Syncrude as it produces a crude oil product similar to our oil and gas activities even though these operations are considered mining activities under SEC regulations.

A. Reserve Quantity Information

Our net proved reserves and changes in those reserves for our conventional operations (excluding Syncrude) are disclosed below. The net proved reserves represent management's best estimate of proved oil and natural gas reserves after royalties. Reserve estimates for each property are prepared internally each year, and at least 80% of the reserves (including Syncrude) have been assessed by independent qualified reserves consultants.

Estimates of crude oil and natural gas proved reserves are determined through analysis of geological and engineering data, and demonstrate reasonable certainty that they are recoverable from known reservoirs under economic and operating conditions that existed at year end. See Critical Accounting Estimates in Item 7 for a description of our reserves estimation process.

	Total		Yemen [1]	Canada			United States		United Kingdom		Other Countries [3]
Conventional oil and bitumen are in mmbbls and natural gas is in bcf	Oil	Gas	Oil	Oil	Gas	Bitumen [2]	Oil	Gas	Oil	Gas	Oil
Proved Developed and Undeveloped Reserves [4]											
December 31, 2002	**324**	**803**	**100**	**155**	**524**	**1**	**58**	**279**	**–**	**–**	**10**
Extensions and Discoveries	48	33	36	10	20	–	1	13	–	–	1
Purchases of Reserves in Place	19	21	–	–	–	–	19	21	–	–	–
Sales of Reserves in Place	(24)	(7)	–	(24)	(6)	–	–	(1)	–	–	–
Revisions of Previous Estimates	(31)	(99)	(5)	(31)	(88)	3	(2)	(11)	–	–	4
Production	(47)	(90)	(21)	(13)	(45)	–	(9)	(45)	–	–	(4)
December 31, 2003	**289**	**661**	**110**	**97**	**405**	**4**	**67**	**256**	**–**	**–**	**11**
Extensions and Discoveries	244	33	1	3	18	239	1	15	–	–	–
Purchases of Reserves in Place	127	23	–	1	–	–	–	–	126	23	–
Sales of Reserves in Place	(1)	(3)	–	(1)	(2)	–	–	(1)	–	–	–
Revisions of Previous Estimates	(265)	(25)	(12)	(11)	(7)	(243)	(6)	(9)	3	(9)	4
Production	(43)	(89)	(19)	(10)	(42)	–	(10)	(46)	(1)	(1)	(3)
December 31, 2004	**351**	**600**	**80**	**79**	**372**	**–**	**52**	**215**	**128**	**13**	**12**
Extensions and Discoveries	15	111	5	4	47	–	1	57	5	7	–
Purchases of Reserves in Place	2	–	–	2	–	–	–	–	–	–	–
Sales of Reserves in Place	(28)	(80)	–	(28)	(80)	–	–	–	–	–	–
Revisions of Previous Estimates	9	(18)	(3)	2	3	–	(5)	(21)	15	–	–
Production	(45)	(81)	(23)	(9)	(37)	–	(7)	(36)	(5)	(8)	(1)
December 31, 2005	**304**	**532**	**59**	**50**	**305**	**–**	**41**	**215**	**143**	**12**	**11**
Proved Developed Reserves [5]											
December 31, 2003	216	576	63	87	367	4	54	209	–	–	8
December 31, 2004	199	518	49	72	348	–	48	166	20	4	10
December 31, 2005	**154**	**438**	**46**	**44**	**275**	**–**	**37**	**161**	**17**	**2**	**10**

Notes:

1 Under the terms of the Masila and the Block 51 production sharing contracts, production is divided into cost recovery oil and profit oil. Cost recovery oil provides for the recovery of all our costs and those of our partners. Remaining production is profit oil, which is shared between the partners and the Government of Yemen based on production rates, with the partners' share ranging from 20% to 33%. The Government's share of profit oil represents its royalty interest and an amount for income taxes payable in Yemen. Yemen's net proved reserves have been determined using the economic interest method and include our share of future cost recovery and profit oil after the Government's royalty interest, but before reserves relating to income taxes payable. Under this method, reported reserves will increase as oil prices decrease (and vice versa) as the barrels necessary to achieve cost recovery change with prevailing oil prices. Production includes volumes used for fuel.

2 Represents bitumen reserves from the insitu recovery of Canadian oil sands, rather than upgraded synthetic crude oil reserves to be sold.

3 Represents reserves in Australia, Nigeria and Colombia.

4 Proved oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and natural gas liquids that geological and engineering data demonstrate with reasonable certainty can be recovered in future years from known reservoirs under existing economic and operating conditions. Reserves are considered "proved" if they can be produced economically, as demonstrated by either actual production or conclusive formation test.

5 Proved developed oil and gas reserves are expected to be recovered through existing wells with existing equipment and operating methods.

Our net proved reserves and changes in those reserves for our Syncrude operations are disclosed below. Additional disclosures required by SEC Industry Guide 7 are on pages 20 and 21. The net proved reserves represent management's best estimate of proved synthetic reserves after royalties. Reserve estimates are prepared internally each year, and at least 80% of our reserves (including oil and gas activities) have been assessed by independent qualified reserves consultants.

Estimates of Syncrude's synthetic crude oil reserves are based on detailed geological and engineering assessments of the bitumen volume in-place, the mining plan, historical extraction recovery and upgrading yield factors, installed plant operating capacity and operating approval limits. The in-place volume, depth and grade are established through extensive and closely spaced core drilling. In accordance with the approved mining plan, there are an estimated 1,960 million tons of economically extractable oil sands in the Base and North Mines, with an average bitumen grade of 10.6 weight percent. The Aurora North Mine contains an estimated 4,370 million tons of economically extractable oil sands at an average bitumen grade of 11.2 weight percent. Aurora South Lease 31 contains measured economically extractable oil sands of 3,915 million tons at an average bitumen grade of 10.8 weight percent.

	Synthetic Crude Oil		
(millions of barrels)	**Base Mine and North Mine** [1]	**Aurora** [2]	**Total**
December 31, 2002	**58**	**168**	**226**
Revision of Previous Estimates	1	4	5
Extensions and Discoveries	–	22	22
Production	(4)	(1)	(5)
December 31, 2003	**55**	**193**	**248**
Revision of Previous Estimates	(1)	(5)	(6)
Extensions and Discoveries	–	19	19
Production	(4)	(2)	(6)
December 31, 2004	**50**	**205**	**255**
Revision of Previous Estimates	–	(4)	(4)
Extensions and Discoveries	–	19	19
Production	(3)	(3)	(6)
December 31, 2005	**47**	**217**	**264**

Notes:

1 Leases 17 and 22

2 Leases 10, 12, 31 and 34.

B. Capitalized Costs (excluding Syncrude operations)

(Cdn$ millions)	Proved Properties	Unproved Properties	Accumulated Depreciation, Depletion, Amortization and Impairment	Capitalized Costs
December 31, 2005				
Yemen	2,243	–	1,841	402
Canada	3,463	143	1,330	2,276
United States	2,323	114	1,159	1,278
United Kingdom	3,603	410	216	3,797
Other Countries	88	161	119	130
Total Capitalized Costs	**11,720**	**828**	**4,665**	**7,883**
December 31, 2004				
Yemen	2,022	16	1,550	488
Canada	3,732	136	2,025	1,843
United States	2,102	147	1,037	1,212
United Kingdom	3,117	382	16	3,483
Other Countries	437	98	408	127
Total Capitalized Costs	**11,410**	**779**	**5,036**	**7,153**
December 31, 2003				
Yemen	1,881	17	1,497	401
Canada	3,271	129	1,863	1,537
United States	2,034	123	892	1,265
Other Countries	454	85	420	119
Total Capitalized Costs	**7,640**	**354**	**4,672**	**3,322**

C. Costs Incurred (excluding Syncrude operations)

		Oil and Gas				
(Cdn$ millions)	Total Oil and Gas	Yemen	Canada	United States	United Kingdom	Other
Year Ended December 31, 2005						
Property Acquisition Costs						
Proved	20	–	17	3	–	–
Unproved	15	–	–	9	6	–
Exploration Costs	509	44	97	235	61	72
Development Costs	1,896	236	947	139	560	14
Asset Retirement Costs	196	13	58	45	80	–
Total Costs Incurred	**2,636**	**293**	**1,119**	**431**	**707**	**86**
Year Ended December 31, 2004						
Property Acquisition Costs						
Proved	1,774	–	4	–	1,770	–
Unproved	1,491	–	–	–	1,491	–
Exploration Costs	339	22	56	162	4	95
Development Costs	1,102	267	491	267	53	24
Asset Retirement Costs	168	3	27	4	134	–
Total Costs Incurred	**4,874**	**292**	**578**	**433**	**3,452**	**119**
Year Ended December 31, 2003						
Property Acquisition Costs						
Proved	164	–	–	164	–	–
Unproved	38	–	–	38	–	–
Exploration Costs	291	34	51	109	–	97
Development Costs	752	219	259	249	–	25
Asset Retirement Costs	185	–	69	62	–	54
Total Costs Incurred	**1,430**	**253**	**379**	**622**	**–**	**176**

D. Results of Operations for Producing Activities (excluding Syncrude operations)

(Cdn$ millions)	Total Oil and Gas	Oil and Gas Yemen	Canada [1]	United States	United Kingdom	Other Countries [1]
Year Ended December 31, 2005						
Net Sales	3,263	1,377	609	792	366	119
Production Costs	511	150	158	96	95	12
Exploration Expense	251	12	24	100	51	64
Depreciation, Depletion, Amortization and Impairment	1,008	354	197	234	210	13
Other Expenses (Income)	335	40	125	83	(8)	95
	1,158	821	105	279	18	(65)
Income Tax Provision (Recovery)	411	285	32	99	7	(12)
Results of Operations	**747**	**536**	**73**	**180**	**11**	**(53)**
Year Ended December 31, 2004						
Net Sales	2,538	921	622	811	36	148
Production Costs	437	109	156	106	6	60
Exploration Expense	246	2	21	138	3	82
Depreciation, Depletion, Amortization and Impairment	712	169	240	258	18	27
Other Expenses (Income)	106	4	38	19	–	45
	1,037	637	167	290	9	(66)
Income Tax Provision (Recovery)	406	222	75	104	4	1
Results of Operations	**631**	**415**	**92**	**186**	**5**	**(67)**
Year Ended December 31, 2003						
Net Sales	2,338	827	675	707	–	129
Production Costs	382	92	159	86	–	45
Exploration Expense	201	17	35	89	–	60
Depreciation, Depletion, Amortization and Impairment	945	168	510	207	–	60
Other Expenses (Income)	49	4	26	(1)	–	20
	761	546	(55)	326	–	(56)
Income Tax Provision (Recovery)	221	191	(82)	115	–	(3)
Results of Operations	**540**	**355**	**27**	**211**	**–**	**(53)**

Note:

1 Includes results of discontinued operations (see Note 14).

E. Standardized Measure of Discounted Future Net Cash Flows and Changes Therein (excluding Syncrude operations)

The following disclosure is based on estimates of net proved reserves (excluding Syncrude) and the period during which they are expected to be produced. Future cash inflows are computed by applying year-end prices to our after royalty share of estimated annual future production from proved oil and gas reserves (excluding Syncrude operations). Future development and production costs to be incurred in producing and further developing the proved reserves are based on year-end cost indicators. Future income taxes are computed by applying year-end statutory-tax rates. These rates reflect allowable deductions and tax credits, and are applied to the estimated pre-tax future net cash flows.

Discounted future net cash flows are calculated using 10% mid-period discount factors. The calculations assume the continuation of existing economic, operating and contractual conditions. However, such arbitrary assumptions have not proved to be the case in the past. Other assumptions could give rise to substantially different results.

We believe this information does not in any way reflect the current economic value of our oil and gas producing properties or the present value of their estimated future cash flows as:

- no economic value is attributed to probable and possible reserves;
- use of a 10% discount rate is arbitrary; and
- prices change constantly from year-end levels.

(Cdn$ millions)	Total	Yemen	Canada	United States	United Kingdom	Other Countries
December 31, 2005						
Future Cash Inflows	23,040	3,675	4,558	5,002	9,190	615
Future Production Costs	5,477	807	1,886	811	1,892	81
Future Development Costs	1,093	153	124	268	534	14
Future Dismantlement and Site Restoration Costs, Net	778	20	180	193	381	4
Future Income Tax	4,496	795	244	1,107	2,172	178
Future Net Cash Flows	11,196	1,900	2,124	2,623	4,211	338
10% Discount Factor	3,154	338	811	697	1,209	99
Standardized Measure	**8,042**	**1,562**	**1,313**	**1,926**	**3,002**	**239**
December 31, 2004						
Future Cash Inflows	18,950	3,779	4,747	4,085	5,852	487
Future Production Costs	4,781	722	2,135	613	1,271	40
Future Development Costs	1,477	275	100	185	903	14
Future Dismantlement and Site Restoration Costs, Net	626	4	149	129	336	8
Future Income Tax	2,798	388	382	845	1,058	125
Future Net Cash Flows	9,268	2,390	1,981	2,313	2,284	300
10% Discount Factor	2,978	499	760	631	1,011	77
Standardized Measure	**6,290**	**1,891**	**1,221**	**1,682**	**1,273**	**223**
December 31, 2003						
Future Cash Inflows	14,660	4,416	5,319	4,470	–	455
Future Production Costs	3,651	868	1,980	666	–	137
Future Development Costs	788	412	102	249	–	25
Future Dismantlement and Site Restoration Costs, Net	309	–	112	137	–	60
Future Income Tax	2,152	574	656	854	–	68
Future Net Cash Flows	7,760	2,562	2,469	2,564	–	165
10% Discount Factor	2,243	620	879	691	–	53
Standardized Measure	**5,517**	**1,942**	**1,590**	**1,873**	**–**	**112**

Changes in the Standardized Measure of Discounted Future Net Cash Flows

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

(Cdn$ millions)	2005	2004	2003
Beginning of Year	6,290	5,517	6,369
Sales and Transfers of Oil and Gas Produced, Net of Production Costs	(2,028)	(1,674)	(2,298)
Net Changes in Prices and Production Costs Related to Future Production	3,302	142	(1,249)
Extensions, Discoveries and Improved Recovery, Less Related Costs [1]	977	(71)	740
Changes in Estimated Future Development and Dismantlement Costs	(135)	(122)	(279)
Previous Estimated Future Development and Dismantlement Costs Incurred During the Period	638	604	456
Revisions of Previous Quantity Estimates	478	(223)	(291)
Accretion of Discount	799	692	884
Purchases of Reserves in Place	15	1,764	354
Sales of Reserves in Place	(882)	(20)	(252)
Net Change in Income Taxes	(1,412)	(319)	1,083
End of Year	**8,042**	**6,290**	**5,517**

Note:

1 2004 includes approximately $230 million of negative discounted future net cash flows relating to bitumen reserves based on year-end assumptions.

Item 9. **Changes in and Disagreements with Accountants on Accounting and Financial Disclosure**

There were no disagreements with accountants on accounting and financial disclosure.

Item 9A. **Controls and Procedures**

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15-d-15(e)) as of the end of the period covered by this report. They concluded that, as of the end of the period covered by this report, our disclosure controls and procedures were adequate and effective in ensuring that material information relating to the Company and its consolidated subsidiaries would be made known to them by others within those entities, particularly during the period in which this report was being prepared. Management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and in reaching a reasonable level of assurance, management necessarily is required to apply its judgement in evaluating the cost-benefit relationship of possible controls and procedures.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f)). Under the supervision and with the participation of our management, including our principal executive officer (CEO) and principal financial officer (CFO), we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation, we concluded that our internal control over financial reporting is effective as of December 31, 2005. We have documented this assessment and made this assessment available to our independent registered Chartered Accountants. We recognize that all internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

There was one important exclusion from our assessment. Our 7.23% working interest in the Syncrude joint venture was excluded from our assessment as we do not have the ability to dictate or modify this entity's internal control over financial reporting, and we do not have the practical ability to assess those controls. Our 7.23% working interest in the Syncrude joint venture represents 7.8% of our consolidated total assets and 8.2% of our consolidated revenues as at and for the year ended December 31, 2005. Despite this exclusion, we have assessed our internal control over financial reporting with respect to the inclusion of our share of this joint venture and its results for the year in our consolidated financial statements. Further financial information with respect to the Syncrude joint venture is in the Syncrude segment of Note 20 to our consolidated financial statements.

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2005, has been audited by Deloitte & Touche LLP, independent registered Chartered Accountants, as stated in their report which is on page 132 of this Form 10-K.

CHANGES IN INTERNAL CONTROLS

We have continually had in place systems relative to internal control over financial reporting. During 2005, we continued to improve and enhance our financial reporting systems with the ongoing implementation of our existing Systems, Applications, and Products in Data Processing (SAP) system into our chemicals operations. We also improved our controls with respect to SAP segregation of duties, database access and password management. The conversion of data and the implementation and operation of SAP has been continually monitored and reviewed.

Effective April 27, 2005, Thomas O'Neill was appointed Chair of our Audit and Conduct Review Committee.

We have evaluated these changes and confirm that there have been no other changes in our internal control over financial reporting during the fourth quarter of 2005 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Based on these evaluations, there were no material weaknesses in these internal controls requiring corrective action. As a result, no such corrective action was taken.

In 2006, we expect to implement our SAP system into our UK operations and, in keeping pace with growth in our US operations, we expect to implement additional inventory tracking and procure to pay process controls.

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of Nexen Inc.:

We have audited management's assessment, included in the foregoing Management's Report on Internal Control over Financial Reporting that Nexen Inc. (the "Company") maintained effective internal control over financial reporting as at December 31, 2005, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). As described in Management's Report on Internal Control over Financial Reporting, management excluded from their assessment the internal control over financial reporting at the Syncrude joint venture because the Company does not have the ability to dictate or modify controls at this entity and does not have the ability to assess, in practice, the controls at this entity. The interest in the Syncrude joint venture constitutes total assets and revenues of 7.8% and 8.2%, respectively, of the related consolidated financial statement amounts as at and for the year ended December 31, 2005. Accordingly, our audit did not include the internal control over financial reporting at the Syncrude joint venture. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections or any evaluation of effectiveness of the internal control over financial reporting to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as at December 31, 2005, is fairly stated, in all material respects, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as at December 31, 2005, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of Nexen Inc. as at and for the year ended December 31, 2005, and our report dated February 7, 2006, expressed an unqualified opinion on those financial statements and included a separate report on Canada-United States of America reporting differences.

Calgary, Canada

February 7, 2006

(signed) "Deloitte & Touche LLP"

Independent Registered Chartered Accountants

Effective governance ensures Nexen continues to be both economically successful and globally responsible. Our Board sets the direction. Management keeps us **on** course. And employees take responsibility every day at work.

see the **value**

corporate governance

PARTS III AND IV

Items 10 to 15

PART III

Item 10. **Directors and Executive Officers of the Registrant**

DIRECTORS

According to our Articles, Nexen must have between three and 15 directors. On January 5, 2004, the Board determined that, until changed, there will be 11 directors.

Our By-Laws provide that directors will be elected at the annual general meeting of shareholders (AGM) each year and will hold office until their successors are elected. All of our current directors were elected at the last AGM.

This table shows our directors' principal occupations or employment during the past five years and any other directorships they held in public companies as at February 17, 2006. The following directors are management nominees for election to the Board.

Name (Age)	**Principal Occupation**	**Other Directorships**	**Nexen Director Since**
Charles W. Fischer (55)	President and Chief Executive Officer (CEO) of Nexen Formerly: Executive Vice President and Chief Operating Officer (COO)		2000
Dennis G. Flanagan [1, 2, 3] (66)	Retired oil executive.	Canexus Income Fund (Chair) NAL Oil & Gas Trust	2000
David A. Hentschel [1, 2] (72)	Retired oil executive. Formerly: Oil and Gas consultant. Prior to that, Chair and CEO of Occidental Oil and Gas Corporation.	Cimarex Energy Co.	1985
S. Barry Jackson [1] (53)	Retired oil executive. Formerly: President and CEO of Crestar Energy Inc. and formerly Chair of Resolute Energy Inc. and Chair of Deer Creek Energy Limited.	Cordero Energy Inc. TransCanada Corporation and TransCanada PipeLines Limited (Chair)	2001
Kevin J. Jenkins [1, 2] (49)	Managing Director of TriWest Capital Management Corp. Formerly: President and CEO of The Westaim Corporation.		1996
Eric P. Newell, O.C. (61)	Retired Chair and CEO of Syncrude Canada Ltd.	Canfor Corporation	2004
Thomas C. O'Neill [1, 2] (60)	Retired Chair of PwC Consulting. Formerly: CEO of PwC Consulting. Prior to that, COO of PricewaterhouseCoopers LLP, Global. Prior to that, CEO of PricewaterhouseCoopers LLP, Canada.	BCE Inc. Loblaw Companies Limited Dofasco Inc. [4] Adecco S.A.	2002
Francis M. Saville, Q.C. (67)	Chair of Nexen Inc. Counsel to Fraser Milner Casgrain LLP, Barristers and Solicitors. Formerly: Senior Partner and Vice Chair of Fraser Milner Casgrain LLP, Barristers and Solicitors.		1994
Richard M. Thomson, O.C. [1, 2] (72)	Retired banking executive.	The Thomson Corporation Trizec Properties Inc.	1997
John M. Willson (66)	Retired President and CEO of Placer Dome Inc.	Aber Diamond Corporation Finning International Inc. Pan American Silver Corporation	1996
Victor J. Zaleschuk (62)	Retired President and CEO of Nexen.	Cameco Corporation (Chair) Agrium Inc.	1997

Notes:

1 Members of Nexen's Audit and Conduct Review Committee as of February 16, 2006. All members of the Committee are independent pursuant to Nexen's Categorical Standards for Director Independence which meet or exceed all applicable regulations.

2 Financial Experts on Nexen's Audit and Conduct Review Committee.

3 Mr. Flanagan was a director of Elek-Tek Inc., a US public computer retailing company, that was subject to bankruptcy proceedings in 1998.

4 Subsequent to February 17, 2006, Dofasco Inc. was acquired by Arcelor S.A., and Mr. O'Nell resigned as a director of Dofasco Inc. on February 21, 2006.

INDEPENDENCE AND BOARD COMMITTEES

Director's independence was affirmatively determined by the Board in reference to our current Categorical Standards for Director Independence (Categorical Standards), which were adopted on February 17, 2006. Our Categorical Standards meet or exceed the requirements set out in US Securities and Exchange Commission (SEC) rules and regulations, the *Sarbanes-Oxley Act of 2002* (Sarbanes-Oxley), the New York Stock Exchange (NYSE) rules, *National Policy 58-201 Corporate Governance Guidelines, Multilateral Instrument 52-110 Audit Committees* and applicable provisions of *National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities*.

The table below sets out committee memberships and whether or not each director has been determined by the Board to be independent. Of the two non-independent directors:

- Mr. Newell is not independent, because a Nexen officer sits on the compensation committee of Syncrude, where Mr. Newell was formerly CEO. If circumstances remain the same, Mr. Newell will be independent after January 2, 2007 (three years after his retirement from Syncrude).
- Mr. Fischer is not independent as he is the President and CEO of Nexen.

	Committees (Number of Members)					
	Audit and Conduct Review [1, 2] (6)	**Compensation and Human Resources** [1] (6)	**Corporate Governance and Nominating** [1] (6)	**Finance** (7)	**Reserves Review** [3] (7)	**Safety, Environment and Social Responsibility** (7)
Independent Outside Directors						
Dennis G. Flanagan [4]	√		√	√	Chair	
David A. Hentschel [4]	√	√			√	√
S. Barry Jackson	√	√			√	Chair
Kevin J. Jenkins [4]	√		√	Chair		√
Thomas C. O'Neill [4]	Chair		√		√	√
Francis M. Saville, Q.C. [5, 6]		√	√	√		√
Richard M. Thomson, O.C. [4]	√	√	Chair	√		
John M. Willson		Chair		√	√	√
Victor J. Zaleschuk		√	√	√	√	
Outside Director—Not Independent						
Eric P. Newell, O.C.				√	√	√
Management Director—Not Independent						
Charles W. Fischer						

Notes:

1 All members of the Audit and Conduct Review Committee, Corporate Governance and Nominating Committee, and Compensation and Human Resources Committee are independent. All members of the Audit and Conduct Review Committee are independent under additional regulatory requirements for audit committee members. Mr. Jackson and Mr. Jenkins were appointed to the Audit and Conduct Review Committee on April 27, 2005, but pursuant to the Committee mandate, automatically ceased to be committee members when, in each case, his child was a summer student who received employment income from Nexen in the summer of 2005. Both were reappointed on February 16, 2006, as they were again independent for audit committee purposes.

2 The Board has considered the circumstances of Mr. O'Neill's service on five public company audit committees, including Nexen's. Mr. O'Neill is retired and holds neither a full nor part-time employee position. His only commitments are to the Boards and Committees on which he serves. Mr. O'Neill was a chartered accountant for more than 30 years, having joined the audit firm of Price Waterhouse (now part of PricewaterhouseCoopers) in 1967. Accordingly, the Board has determined that service as an audit committee member or chair on four other public companies does not impair Mr. O'Neill's ability to serve as Chair of Nexen's Audit and Conduct Review Committee.

3 A majority of the Reserves Review Committee members is independent.

4 A financial expert under US regulatory requirements.

5 Mr. Saville retired as a Partner and Vice Chair of Fraser Milner Casgrain (FMC) in January 2004. Since February 1, 2004, he has been Counsel to the firm. Mr. Saville does not solicit or participate in any work done by FMC for Nexen and, as Counsel with FMC, does not receive any share of the fees paid to FMC by Nexen.

6 Mr. Saville, Chair of the Board, presides at the regularly scheduled in camera sessions of the non-management directors.

COMMUNICATING WITH THE BOARD

Shareholders may write to the Board or any member or members of the Board in care of the following address:

By mail to: Nexen Inc.
801 – 7th Avenue S.W., Calgary, Alberta, T2P 3P7

Attention: John B. McWilliams,
Senior Vice President, General Counsel and Secretary

By email to: board@nexeninc.com

Nexen receives a number of inquiries on a large range of subjects every day. As a result, the Board is not able to respond to all shareholder inquiries directly and has consulted with management to develop a process to assist in managing inquiries directed to the Board or its members.

Letters and emails addressed to the Board, any of its members or the independent directors, as a group, are reviewed to determine if a response from the Board is appropriate. While the Board oversees management, it does not participate in the day-to-day functions and operations of Nexen and is not normally in the best position to respond to inquiries on those matters. Inquiries on operations or day-to-day management of Nexen will be directed to the appropriate personnel within Nexen for a response. The Board has instructed the Secretary to review all correspondence and, in his discretion, not forward items if they:

- are not relevant to Nexen's operations, policies and philosophies;
- are commercial in nature; or
- are not appropriate for consideration by the Board.

All inquiries will receive a written response from either the Board or management, as appropriate. The Secretary maintains a log of all correspondence addressed to members of the Board. Directors may review the log at any time and request copies of any correspondence received.

EXECUTIVE OFFICERS

The Board determines the term of office for each executive officer. Below are Nexen's officers, including prior offices and non-executive positions for officers who have held their current executive positions with Nexen for less than five years. Start dates are indicated for officer positions with Nexen.

Officer (Age)	**Current and Past Position(s) with Nexen**	**Effective Date of Current Position**	**Executive Officer Since**
Charles W. Fischer (55)	President and CEO and a director Formerly: Executive Vice President and COO since May 14, 1997	June 1, 2001	1994
Marvin F. Romanow (50)	Executive Vice President and CFO Formerly: Senior Vice President, Finance and CFO since February 19, 1999	June 1, 2001	1997
Laurence Murphy (54)	Senior Vice President, International Oil and Gas	January 1, 1999	1998
John B. McWilliams, Q.C. (58)	Senior Vice President, General Counsel and Secretary	May 11, 1993	1987
Douglas B. Otten (63)	Senior Vice President, United States Oil and Gas	May 12, 1998	1990
Roger D. Thomas (53)	Senior Vice President, Canadian Oil and Gas	February 19, 1999	1998
Nancy F. Foster (46)	Vice President, Human Resources and Corporate Services	July 11, 2000	2000
Gary H. Nieuwenburg (47)	Vice President, Synthetic Crude Formerly: Vice President, Corporate Planning and Business Development since February 16, 2001	July 11, 2002	2001
Kevin J. Reinhart (47)	Vice President, Corporate Planning and Business Development Formerly: Treasurer since October 20, 1998	July 11, 2002	1994
Una M. Power [1] (41)	Treasurer Formerly: Controller and Director, Corporate Insurance since May 2, 2002 Controller and Director, Risk Management since December 1, 1998	July 11, 2002	1998
Michael J. Harris (42)	Controller Formerly: Manager, Corporate Finance—Treasury since December 1, 2000	December 10, 2002	2002

Note:
1 Ms. Power concurrently maintained her position as Controller until December 10, 2002.

ETHICS POLICY

Under Nexen's Ethics Policy, all directors, officers and employees must demonstrate a commitment to ethical business practices and behaviour in all business relationships, both within and outside of Nexen. An employee is not permitted to commit an unethical, dishonest or illegal act or to instruct other employees to do so. Our Ethics Policy has been adopted as a code of ethics applicable to our principal executive officer, principal financial officer and principal accounting officer or controller.

Any waivers of or changes to the Ethics Policy must be approved by the Board of Directors and appropriately disclosed. There were no waivers of the Ethics Policy during 2005. Our Ethics Policy provides for an external Integrity Hotline which has been in place since February 1, 2005.

Our Ethics Policy is available at www.nexeninc.com, and we intend to provide disclosure regarding waivers of or changes to our Ethics Policy in this manner. In addition, our Ethics Policy is filed on SEDAR, and all future amendments to the Ethics Policy will be filed on SEDAR. A hard copy of the Ethics Policy can be requested from the Assistant Secretary by telephone at 403.699.4000, by facsimile at 403.716.0468 or by email at assistant_secretary@nexeninc.com.

CORPORATE GOVERNANCE

Nexen's Board of Directors takes its duties and responsibilities for good corporate governance seriously. Nexen supports and conducts business according to the rules of the Toronto Stock Exchange (TSX), NYSE, *National Policy 58-201 Corporate Governance Guidelines* and *Multilateral Instrument 52-110 Audit Committees*. Except as noted below with regard to DSUs, Nexen's corporate governance practices comply with the corporate governance practices followed by domestic companies under NYSE listing standards.

Nexen has a DSU plan for non-executive directors as described on page 144. For this plan, Nexen follows the TSX rules which, unlike the NYSE rules, exempt plans from shareowner approval where the common shares issued under the plan are purchased on the open market rather than being newly issued shares.

On February 23, 2006, our CEO certified to the NYSE that he was unaware of any violation by Nexen of the NYSE's corporate governance listing standards. Nexen also provided the required Annual Written Affirmation to the NYSE on February 23, 2006 and an Interim Written Affirmation on February 17, 2006. As well, our CEO and CFO have certified the quality of Nexen's public disclosure to the SEC.

All Committee Mandates, including those for the Audit and Conduct Review Committee, the Compensation and Human Resources Committee and the Corporate Governance and Nominating Committee, and our Corporate Governance Policy and Categorical Standards are available at www.nexeninc.com, and we intend to provide disclosure in this manner. Shareholders wishing to receive a copy of these documents may contact the Assistant Secretary by telephone at 403.699.4000, by facsimile at 403.716.0468 or by email at assistant_secretary@nexeninc.com.

REPORTING CONCERNS

Any concerns about Nexen's financial statements, accounting practices or internal controls may be directed to the Chair of the Audit and Conduct Review Committee as set out in the Ethics Policy or reported through EthicsPoint, the independent, third-party service provider, as set out below.

If Nexen employees, customers, suppliers, partners and other external stakeholders have a concern, they are encouraged to raise it with Nexen's Integrity Resource Centre:

By mail to:	Nexen Inc. 801 - 7th Avenue S.W., Calgary, Alberta, T2P 3P7
Attention:	Integrity Resource Centre
or by email to:	integrity@nexeninc.com
or by telephone to:	403.699.4727

They may also report concerns through Nexen's Integrity Hotline. The Integrity Hotline is a secure reporting system which is owned and managed by EthicsPoint, an independent third-party service provider. To find out more about Nexen's Integrity Hotline and for toll free numbers for other countries, refer to www.nexeninc.com, and click on the "Integrity Hotline" link at the top of the page.

The Integrity Hotline can also be accessed:

Through the internet:	www.ethicspoint.com
By telephone (toll-free):	North America 1.866.ETHICSP (1.866.384.4277)

Item 11. **Executive Compensation**

SUMMARY COMPENSATION

		Annual Compensation			Long-Term Compensation Awards		
Name and Principal Position	Year	Salary ($)	Bonus [1] ($)	Other Annual Compensation ($)	Securities Underlying Options Granted [2] (#)	Restricted Shares or Restricted Share Units ($)	All Other Compensation ($)
Charles W. Fischer President and CEO	2005	975,000	1,200,000	–	200,000	–	58,500 [3]
	2004	847,917	1,310,000	–	300,000	–	50,875 [3]
	2003	725,000	600,000	–	200,000	–	43,500 [3]
Marvin F. Romanow Executive Vice President and CFO	2005	486,000	525,000	–	62,000	–	29,160 [3]
	2004	462,500	555,000	–	114,000	–	27,750 [3]
	2003	440,500	267,000	–	110,000	–	26,430 [3]
Douglas B. Otten Senior Vice President, United States Oil and Gas	2005	423,489	212,048	–	50,000	–	13,813 [3] / 61,654 [4]
	2004	438,005	299,345	–	80,000	–	26,280 [3] / 63,536 [4]
	2003	416,152	226,170	–	74,000	–	24,969 [3] / 60,221 [4]
Laurence Murphy Senior Vice President, International Oil and Gas	2005	405,000	205,000	–	50,000	–	24,300 [3]
	2004	385,500	565,000	–	80,000	–	23,130 [3]
	2003	366,500	196,000	–	74,000	–	21,990 [3]
Roger D. Thomas Senior Vice President, Canadian Oil and Gas	2005	394,250	400,000	–	50,000	–	18,000 [3]
	2004	373,250	225,000	–	80,000	–	16,740 [3]
	2003	356,500	190,000	–	64,000	–	21,390 [3]
Thomas A. Sugalski [5] Senior Vice President, Chemicals	2005	232,367	1,437,440	–	–	–	16,214 [3] / 39,335 [6]
	2004	403,465	208,240	–	60,000	–	24,208 [3] / 56,165 [6]
	2003	384,439	156,380	–	60,000	–	23,066 [3] / 53,395 [6]

Notes:

For the CEO and five other highest compensated officers, which include the CFO and the former Senior Vice President, Chemicals who retired on August 1, 2005:

1 Annual bonuses are determined based on performance during the year and are paid to the employee in the following year pursuant to the annual incentive plan. The bonuses indicated were the payments made in the year shown and include special bonuses of $300,000, $175,000 and $200,000 for Messrs. Fischer, Romanow and Thomas, respectively, for the successful divestitures. The bonus for Mr. Sugalski includes a payment of $1,239,933 under a Special Separation Agreement dated January 28, 2005, effective August 1, 2005.

2 Reflect the two-for-one split of issued and outstanding common shares that occurred on May 10, 2005 (TSX) and on May 18, 2005 (NYSE).

3 Reflect Nexen contributions to the Employee Savings Plan.

4 Nexen contributed to a Qualified Defined Contribution Plan and a Restoration Plan with Nexen Petroleum U.S.A. Inc. for Mr. Otten.

5 Mr. Sugalski retired on August 1, 2005, and is included because he would have been one of the highest compensated officers, except that he was not serving as an officer of Nexen at December 31, 2005.

6 Nexen contributed to a Qualified Defined Contribution Plan and a Restoration Plan with Nexen Chemicals U.S.A. Inc. for Mr. Sugalski.

OPTIONS

Pursuant to Nexen's Tandem Option Plan (TOP), the Board, on the recommendation of the Compensation and Human Resources Committee, may grant options to Nexen officers and employees. Nexen does not receive any consideration when options are granted. The option exercise price is the market price of Nexen's common shares on the TSX for Canadian-based employees or on the NYSE for US-based employees, when the option is granted.

The Board determines the term of each option, to a maximum of ten years, and the vesting schedule. For all options granted before February 2001, options have a term of ten years; 20% of the grant vests after six months and then 20% vests each year for four years on the anniversary of the grant. In February 2001, the Compensation and Human Resources Committee and the Board approved an amendment that each option granted has a term of five years and vests one-third each year over three years. Generally, if a change of control event occurs (as defined in the TOP Plan), all issued but unvested options will become vested.

Option Grants During 2005

Name	Securities Underlying Options Granted (#)	% of Total Options/Stock Appreciation Rights Granted to Employees in Financial Year	Exercise or Base Price [1] ($/Security)	Expiration Date	Potential Realizable Value at Assumed Annual Rates of Stock Price Appreciation for Option Term 5% ($)	10% ($)
Charles W. Fischer	200,000	4.1	54.57	December 6, 2010	3,015,337	6,663,106
Marvin F. Romanow	62,000	1.3	54.57	December 6, 2010	934,754	2,065,563
Douglas B. Otten	50,000	1.0	US$47.21	December 6, 2010	790,225	1,746,192
Laurence Murphy	50,000	1.0	54.57	December 6, 2010	753,834	1,665,777
Roger D. Thomas	50,000	1.0	54.57	December 6, 2010	753,834	1,665,777
Thomas A. Sugalski	–	–	–	–	–	–

Note:
1 Equal to the market value of securities underlying the options on the date of grant.

Options Exercised During 2005 and Financial Year-end Option Values

Name	Securities Acquired on Exercise (#)	Value Realized [1] ($)	Number of Securities Underlying Unexercised Options at Financial Year-end Exercisable/Unexercisable (#)	Value of Unexercised In-The-Money-Options at Financial Year-end Exercisable/Unexercisable ($)
Charles W. Fisher	116,000	4,375,840	1,146,000 / 464,000	44,538,700 / 8,329,250
Marvin F. Romanow	20,000	710,000	492,460 / 173,540	18,515,798 / 3,530,992
Douglas B. Otten	51,694	789,490	246,636 / 127,220	9,690,667 / 2,634,443
Laurence Murphy	182,900	4,226,207	99,880 / 127,220	3,373,261 / 2,447,929
Roger D. Thomas	136,000	1,975,320	160,080 / 123,920	5,684,112 / 2,336,818
Thomas A. Sugalski	131,600	5,133,093	– / 59,400	– / 2,012,420

Note:
1 Equals market price at the time of the exercise, minus the exercise price, as defined in the TOP Plan.

EMPLOYEE SAVINGS PLAN

The Summary Compensation Table includes Nexen's contribution to the employee savings plan made on behalf of executive officers. Through payroll deductions, all regular employees may contribute any percentage of their regular earnings to purchase Nexen common shares or mutual fund units or a combination of both. Nexen matches employee contributions to a maximum of 6% of regular earnings. The extent of matching is based on the investment option selected and the employee's length of participation in the plan. The full amount of Nexen's contribution is invested in common shares and is fully vested immediately. Employee and employer contributions may be allocated to registered or non-registered accounts. Employees may vote the Nexen common shares they hold in the Employee Savings Plan.

For employees in the US, the savings plan is intended to qualify under Sections 401(a) and 501(a) of the Internal Revenue Code. Nexen matches employee contributions to a maximum of 6% of eligible compensation. The full amount of Nexen's matching contribution is provided in cash, which is fully vested immediately.

BENEFIT PLANS

All named executive officers, except Mr. Sugalski and Mr. Otten, are members of Nexen's Defined Benefit Pension Plan and of the Executive Benefit Plan. Mr. Otten is employed in the US and is a member of a qualified 401(k) savings plan, a qualified defined contribution pension plan and a non-qualified restoration plan. Mr. Sugalski participated in the 401(k) savings plan, a qualified defined contribution pension plan and a non-qualified restoration plan until his retirement.

Defined Benefit Pension Plan (Canada)

Under this registered plan, participants must contribute 3% of their regular gross earnings, up to an allowable maximum. On retirement, participants are entitled to receive a benefit equal to 1.8% (1.7% for years prior to 2005) of their average earnings for the 36 highest paid consecutive months during the ten years before retirement, multiplied by the number of years of credited service. The plan is integrated with the Canada Pension Plan (CPP) to provide a maximum offset of one-half of the prevailing CPP benefit. Nexen was not required to contribute to the Defined Benefit Pension Plan in 2005.

Pension benefits earned prior to January 1, 1993 may be indexed on an ad hoc basis. Pension benefits earned after December 31, 1992 will be indexed annually at an amount between 0% and 5% and equal to the greater of:

- 75% of the increase in the Canadian Consumer Price Index, less 1%; and
- 25% of the increase in the Canadian Consumer Price Index.

Effective January 1, 2005, the plan was amended to permit participants to periodically switch between the Defined Benefit and Defined Contribution Pension Plans at different stages in their career. In addition, the plan's benefit accrual formula increased from 1.7% to 1.8% for participation after January 1, 2005. Plan participants have an opportunity to further increase their benefit accrual formula on a go-forward basis, from 1.8% to 2%, through additional tax-effective employee contributions. Employees who choose this option are required to contribute an additional 2% of pensionable earnings to the allowable maximum.

Executive Benefit Plan (Canada)

The Executive Benefit Plan (EBP) provides supplemental retirement benefits for Canadian participants who have earned a retirement benefit in excess of the statutory limits. Ten executive officers, together with all employees who have exceeded the statutory limit with their earned retirement benefits, participate in the EBP. This supplemental benefit provides employees the opportunity to accrue a pension that is more in line with their final earnings level and also ensures competitiveness within our marketplace. Benefits that accrue under the EBP are similar to the underlying registered pension plan formula which provides for benefits of 1.7% for credited service prior to 2005 and 1.8% or 2% for credited service after that. For executive officers, annual incentive payments during the last three years of participation in the EBP are also included for benefit accrual purposes. For the annual incentives, pension benefit is accrued on the lesser of target bonus or actual bonus paid, averaged over the final three years of participation, and the associated pension benefit is payable from the EBP.

The pension expense for the EBP is determined and recognized annually. Benefits payable for the year are paid from the cash flows from Nexen's general operating revenues and reduce the related pension liability. As liabilities under the EBP are not funded, a level of protection is provided to participants through a letter of credit. The letter of credit basically makes participants secured creditors up to the aggregate value of the letter of credit. This is separate from the protection of benefits in the registered Defined Benefit Pension Plan, which is funded. The service cost for the letter of credit was $187,132 in 2005.

At December 31, 2005, as indicated in the notes to our financial statements, Nexen's accumulated benefit obligation (the projected benefit obligation excluding future salary increases) for the EBP was $29.1 million, and the projected benefit obligation was $42.5 million. The projected benefit obligation is an estimate based on contractual entitlements that may change over time. The method used to determine this estimate will not be identical to the method used by other issuers and, as a result, the figures may not be directly comparable across companies. The key assumptions used for the projected benefit obligation were a discount rate of 5.25% per year, a long-term compensation rate increase of 4% per year and an expected average remaining service life of ten years.

Effective January 1, 2005, the EBP was amended to provide a supplemental pension allocation for Defined Contribution Pension Plan participants who are affected by annual statutory contribution limits. In 2005, the supplemental allocation for eligible participants was $18,000 and in 2006, the supplemental allocation for eligible participants will be $25,390. No Canadian executive officer participates in the Defined Contribution Pension Plan.

Defined Contribution Pension Plan (US)

Under this qualified retirement plan, Nexen provides plan participants with a contribution of 6% of eligible compensation up to the Social Security taxable wage base and 11.5% of eligible compensation that exceeds the Social Security taxable wage base. For 2005, the maximum amount of contributions permitted by legislation to qualified defined contribution plans was $42,000 per participant.

Non-Qualified Restoration Plan (US)

This plan is intended to be an unfunded and non-qualified deferred compensation arrangement that provides deferred compensation benefits to a select group of management or highly compensated employees. The plan is established and maintained by Nexen for the purpose of providing benefits in excess of applicable legislative limits.

Estimated Pension Benefit

The table shows the estimated annual pension a retiring executive officer would receive for credited service up to and including December 31, 2004, assuming that the amount in the Summary Compensation Table (page 139) is the officer's final average salary. The annual benefit is based on a pension accrual formula of 1.7% of average earnings less a plan offset. It includes benefits from both the Defined Benefit Pension Plan and the EBP and assumes a retirement age of 65. The normal benefits paid from this plan are joint life and survivor benefits with a five-year guarantee. The benefit is payable for the participant's lifetime and provides the spouse with a survivor benefit of 66 2/3% of the monthly payment. The five-year guarantee means that if the participant dies before receiving 60 monthly payments, the surviving spouse receives the balance of those 60 monthly payments and then the reduced survivor pension of 66 2/3%.

	Years of Service Before January 1, 2005				
Renumeration ($)	**5**	**10**	**15**	**20**	**25**
400,000	33,290	66,579	99,869	133,159	166,448
600,000	50,290	100,579	150,869	201,159	251,448
800,000	67,290	134,579	201,869	269,159	336,448
1,000,000	84,290	168,579	252,869	337,159	421,448
1,200,000	101,290	202,579	303,869	405,159	506,448
1,400,000	118,290	236,579	354,869	473,159	591,448
1,600,000	135,290	270,579	405,869	541,159	676,448
1,800,000	152,290	304,579	456,869	609,159	761,448
2,000,000	169,290	338,579	507,869	677,159	846,448
2,200,000	186,290	372,579	558,869	745,159	931,448
2,400,000	203,290	406,579	609,869	813,159	1,016,448
2,600,000	220,290	440,579	660,869	881,159	1,101,448
2,800,000	237,290	474,579	711,869	949,159	1,186,448

The following table shows the estimated annual pension for credited service earned on and after January 1, 2005, based on a forward looking benefit accrual rate of 2% of final average earnings less a plan offset. It includes benefits from both the Defined Benefit Plan and EBP and assumes a retirement age of 65.

	Years of Service from January 1, 2005				
Renumeration ($)	**5**	**10**	**15**	**20**	**25**
400,000	39,290	78,579	117,869	157,159	196,448
600,000	59,290	118,579	177,869	237,159	296,448
800,000	79,290	158,579	237,869	317,159	396,448
1,000,000	99,290	198,579	297,869	397,159	496,448
1,200,000	119,290	238,579	357,869	477,159	596,448
1,400,000	139,290	278,579	417,869	557,159	696,448
1,600,000	159,290	318,579	477,869	637,159	796,448
1,800,000	179,290	358,579	537,869	717,159	896,448
2,000,000	199,290	398,579	597,869	797,159	996,448
2,200,000	219,290	438,579	657,869	877,159	1,096,448
2,400,000	239,290	478,579	717,869	957,159	1,196,448
2,600,000	259,290	518,579	777,869	1,037,159	1,296,448
2,800,000	279,290	558,579	837,869	1,117,159	1,396,448

When determining the estimated value of future pension benefits for an executive officer, both tables above need to be referenced. For example, a pension estimate based on 35 years of credited service would require the first table for actual credited service up to and including December 31, 2004, and the second table for projected credited service on and after January 1, 2005. When estimating future pension benefits, the final average earnings used should be the same for both tables.

Additional past service credits or accelerated service benefits must be approved by the Board. No accelerated service credits have been authorized. Additional past service credits authorized by the Board for the four named executive officers who participate in the EBP are noted in the table below. Information on the Qualified and Non-Qualified Defined Contribution Plan contributions for the other two named executive officers, Mr. Otten and Mr. Sugalski, is included in the Summary Compensation Table for Executives on page 139.

Name	Years of Credited Service to December 31, 2004	Years of Credited Service from January 1, 2005 (#)	Final Average Earnings [1] ($)	Accrued Annual Pension Benefit [1] ($)	Estimated Annual Pension Benefit at Age 60 [2] ($)
Charles W. Fischer	20.58 [3]	1.00	1,377,639	506,544	792,219
Marvin F. Romanow	17.50 [3,4]	1.00	679,300	239,708	418,678
Laurence Murphy	18.67	1.00	533,933	177,322	252,045
Roger D. Thomas	24.5 [3]	1.00	518,533	222,717	317,953

Notes:

1 All information as of December 31, 2005.

2 Earliest age at which an individual receives full retirement benefits.

3 Ten years of additional past service credits were granted to each of Messrs. Fischer, Romanow and Thomas by the Board in 2001.

4 Mr. Romanow is entitled to additional pension benefit based on pensionable bonus, in recognition of his 7.25 years of service as a participant in Nexen's defined contribution pension plan up to December 31, 2004.

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

The members of the Compensation and Human Resources Committee are in the table on page 136. Mr. Saville, a member of the Compensation and Human Resources Committee, had a relationship requiring disclosure, the details of which are set out under "Certain Relationships" on page 150. Mr. Hentschel and Mr. Zaleschuk were both formerly officers of Nexen, until June 1, 1997 and May 31, 2001, respectively. There are no compensation committee interlocks during 2005.

CHANGE OF CONTROL AGREEMENTS

Nexen has entered into Change of Control Agreements with Messrs. Fischer, Romanow, Otten, Murphy, Thomas and other key executives. The agreements were effective October 1999, amended in December 2000 and amended and restated in December 2001. The agreements recognize that these executives are critical to Nexen's ongoing business. They recognize the need to retain the executives, protect them from employment interruption caused by a change in control and treat them in a fair and equitable manner, consistent with industry standards for executives in similar circumstances.

For the purposes of these agreements, a change of control includes any acquisition of common shares or other securities that carry the right to cast more than 35% of the votes attaching to all common shares and, in general, any event, transaction or arrangement that results in a person or group exercising effective control of Nexen.

If the named executives are terminated following a change in control, they will be entitled to receive salary and benefits for a specified severance period. For Mr. Fischer and Mr. Romanow, the severance period is 36 months. Mr. Fischer and Mr. Romanow may also terminate their employment on a voluntary basis following a change of control with severance periods of 36 and 30 months, respectively. For Messrs. Otten, Murphy and Thomas, the severance period is 30 months.

DIRECTOR COMPENSATION

In December 2005, all director compensation was reviewed and confirmed at the then-current levels, except for an additional annual fee of $14,400 for the Chair of the Audit and Conduct Review Committee. The additional amount reflects the complex duties of the position. Nexen reimburses the directors for out-of-pocket expenses incurred to attend meetings. Directors are paid meeting fees for attending meetings either in person or by telephone conference call. From January 1, 2006, all directors who are not employees are paid:

Annual Board Chair Retainer	$150,000
Annual Board Retainer	$28,100
Annual Committee Retainer	$9,100
Annual Committee Chair Retainer	$5,300
Annual Audit and Conduct Review Committee Additional Annual Chair Retainer [1]	$14,400
Board Committee Meeting Fees	$1,800

Note:

1 The total annual retainer of $28,800 paid to the Chair of the Audit and Conduct Review Committee and includes the Annual Committee Retainer, the Annual Committee Chair Retainer and the Annual Audit and Conduct Review Committee Additional Chair Retainer.

Annual Board and Committee retainers are paid quarterly, in advance, and are pro-rated for partial service, if appropriate. This table sets out the full dollar value of retainers and fees, whether received in cash or Deferred Share Units. All payments were received in cash unless otherwise noted. See "Deferred Share Units" for DSUs granted as directors' performance-based compensation.

Director	Annual Board Retainer	Annual Committee Retainers/ Number of Committees	Annual Committee Chair Retainer	Board Meeting Fees	Committee Meeting Fees	Total Fees Paid in Cash	Total Fees Credited in DSUs
Charles W. Fischer [1]	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Dennis G. Flanagan	$28,100	$36,400/4	$5,300	$16,200	$45,000	$131,000	–
David A. Hentschel	$28,100	$36,400/4	$1,325	$18,000	$39,600	$123,425	–
S. Barry Jackson [4]	$28,100	$31,887/3 [4]	$5,300	$18,000	$32,400	$115,687	–
Kevin J. Jenkins [4]	$28,100	$30,317/3 [4]	$5,300	$16,200	$34,200	$114,117	–
Eric P. Newell, O.C. [2]	$28,100	$27,300/3	–	$16,200	$25,200	–	$96,800
Thomas C. O'Neill	$28,100	$36,400/4	$3,975	$16,200	$48,600	$133,275	–
Francis M. Saville, Q.C. [3]	$140,600	$36,400/4	$1,325	$18,000	$55,800	$252,125	–
Richard M. Thomson, O.C. [2, 3]	$76,314	$36,400/4	$3,597	$18,000	$55,800	–	$190,111
John M. Willson	$28,100	$36,400/4	$5,300	$16,200	$43,200	$129,200	–
Victor J. Zaleschuk	$28,100	$36,400/4	–	$18,000	$52,200	$134,700	–
Total	$441,714	$ 344,304	$31,422	$171,000	$432,000	$1,133,529	$286,911

Notes:

1 As an executive of Nexen, Mr. Fischer is not paid retainers or meeting fees.

2 Details of DSU holdings are set out in the table below.

3 Mr. Saville was appointed Chair of the Board on April 27, 2005, and Mr. Thomson stepped down as Chair of the Board on the same date. Their retainers were pro-rated. Mr. Thomson continues to serve as a Director.

4 Audit and Conduct Review Committee retainer fees were pro-rated to May 2, 2005, for Mr. Jenkins and to July 4, 2005, for Mr. Jackson, the respective dates they ceased to be members of the Committee.

DEFERRED SHARE UNITS

In 2001, a Deferred Share Unit (DSU) plan was approved as an alternative form of compensation for non-executive directors. Under the plan, eligible directors may elect annually to receive all or part of their fees as DSUs, rather than cash. A DSU is a bookkeeping entry that tracks the value of one Nexen common share. On the date cash dividends are paid on Nexen common shares, eligible directors are credited with additional DSUs. The number of DSUs is calculated by dividing the total amount of the dividends that would have been paid if the DSUs on account were common shares by the fair market value on the dividend payment date. DSUs are not paid out until the director leaves the Board, providing an ongoing equity stake in Nexen during the director's term of service. Payments of DSUs may be made in cash or in Nexen common shares purchased on the open market at the time of payment, at Nexen's option.

In 2003, the Board adopted a policy stating that non-executive directors would no longer be granted stock options and non-executive directors are not eligible to receive options under the Tandem Option Plan. DSUs have since been employed as an alternate type of performance-based compensation. In December 2005, all directors who were not employees of Nexen were granted 2,100 DSUs, except for the Board Chair, who was granted 3,200 DSUs. The values of the grants were $114,597 and $174,624, respectively, at the closing market price of Nexen shares on the TSX on December 5, 2005 of $54.57.

Director	DSUs Held as of December 31, 2005 [1]
Charles W. Fischer	None
Dennis G. Flanagan	10,582
David A. Hentschel	10,580
S. Barry Jackson	10,582
Kevin J. Jenkins	17,073
Eric P. Newell, O.C.	16,139
Thomas C. O'Neill	15,505
Francis M. Saville, Q.C.	11,682
Richard M. Thomson, O.C.	22,576
John M. Willson	16,782
Victor J. Zaleschuk	10,582

Note:

1 Number of DSUs has been adjusted to account for Nexen's share split that occurred on May 10, 2005 (TSX) and on May 18, 2005 (NYSE).

DIRECTORS' AND OFFICERS' LIABILITY INSURANCE

Nexen maintains a directors' and officers' liability insurance policy. This policy provides coverage for costs incurred to defend and settle claims against directors and officers to an annual limit of US$130 million with a US$5 million deductible per occurrence. The cost of coverage for 2005 was approximately US$0.9 million.

SHARE OWNERSHIP GUIDELINES FOR DIRECTORS

The Board believes it is important that directors demonstrate their commitment to Nexen's growth through share ownership. The Board has approved a guideline setting out that directors are expected to own or control at least 6,000 shares (DSUs count towards share ownership), to be accumulated over three years. Specific arrangements may be made when a qualified candidate might be prevented from serving by this guideline. The guideline is reviewed by the Board from time to time. Ownership can be achieved by purchasing common shares, participating in the Nexen Dividend Reinvestment Plan or directing retainer fees into DSUs. All directors meet the ownership requirement.

COMPENSATION AND HUMAN RESOURCES COMMITTEE

The Compensation and Human Resources Committee (Committee) is comprised of six independent directors, and its primary purpose is to assist the Board in fulfilling its oversight responsibilities with respect to (i) key compensation and human resources policies; (ii) CEO and executive management compensation; and, (iii) executive management succession and development.

The Committee oversees Nexen's annual incentive plan, the TOP Plan, Stock Appreciation Rights (StARs) Plan and Pension Plan. It reviews and approves executive management's recommendations for the annual salaries, bonuses and grants of TOPs and StARs. The Committee reports to the Board and the Board gives final approval to compensation matters.

The Committee evaluates the performance of the CEO and recommends his compensation which is approved by the independent directors of the Board.

Policies of the Committee

Nexen's policies and practices are consistent with and linked to its strategic business objectives and increased shareowner returns. Within that framework, the Committee's goal is to compensate executives based on performance, at a level competitive with the market, in a manner designed to attract and retain a talented leadership team who are focused on managing Nexen's operations, finances and assets.

To ensure competitiveness, Nexen uses compensation surveys to compare our executive compensation practices to peers, primarily major Canadian oil and gas and, where relevant, marketing companies. The Committee receives a report annually on CEO compensation from its own independent consultant. The report includes competitive compensation data from a predetermined list of peer companies. The information is used to determine the annual compensation recommendation for the CEO by the Committee.

Compensation Objectives

Nexen's compensation programs are designed to meet performance and competitiveness objectives. They are pay-for-performance plans, with rewards directly linked to planned performance for Nexen and its divisions. Individual performance and contributions are considered in determining awards. Measures are aligned with financial and non-financial goals and shareowner interests.

Competitiveness is assessed using compensation survey information from peers, including energy companies with whom Nexen competes for talent. We assess total compensation and consider the competitiveness of each component.

Our compensation program has three components: base salary, annual cash incentives and long-term incentives. The Committee's goal is to provide total compensation for experienced top-performing employees between the 50th and 75th percentile as compared with compensation levels of peer companies. Nexen's position compared with the market is reviewed annually. The following table provides an overview of the three elements:

Component of Compensation	Type of Compensation	Element	Form	Performance Period
Fixed	Annual	Base Salary	Cash	1 Year
Variable	Annual	Short-Term Incentive	Cash	1 Year
Variable	Long-Term	Long-Term Incentive	TOPs or StARs	Greater than 1 Year [1]

Note:

1 TOPs and StARs have a five-year term and vest one-third each year of the first three years of the term on the anniversary date of the grant.

Pay Mix

The majority of compensation paid to senior executives is at-risk-pay to ensure alignment with shareowners. The actual mix varies depending on the ability of the executive to influence short-term and long-term business results, the level and location of the executive and competitive local market practices. The following table summarizes the target weightings of the various compensation components as a percentage of total compensation.

Position	Base	Annual Incentive	Long-Term Incentive
Chief Executive Officer	26%	19%	55%
Chief Financial Officer	33%	19%	48%
Senior Vice Presidents	34%	14%	52%

Base Salaries

To determine base salaries, Nexen maintains a framework of job levels based on internal comparability and external market data. Base salary decisions are determined by considering the individual's current and sustained performance, skills and potential.

Annual Incentives

The Board approves awards under the annual incentive plan. The Committee determines the total cash available for annual incentive awards by evaluating financial and non-financial criteria, including net income, cash flow and specific goals outlined in a balanced scorecard. Net income and cash flow are commonly used metrics in our industry, and each represents one-quarter of the overall assessment. The remaining one-half of the overall assessment includes qualitative and quantitative targets for growth and operating performance, such as net asset value growth, cost management, safety record, production volumes and reserves growth, among others. Another important measure in the scorecard is the extent to which the operations were conducted in an environmentally safe and socially responsible manner.

The purpose of annual cash incentives is to provide cash compensation that is at risk and depends on the achievement of business and operating objectives. Individual target award levels increase in relation to job responsibilities so the ratio of at risk versus fixed compensation is greater for higher levels of management. Individual awards are intended to reflect a combination of Nexen, personal and business unit performance, along with market competitiveness. Annual incentive awards are typically within a range of 0% to approximately 200% of targeted amounts.

The incentive plan is reviewed annually to ensure we continue to attract, motivate, reward and retain the high-performing and high-potential employees needed to achieve Nexen's business objectives, while demonstrating long-term fiscal responsibility to our shareowners.

Consistent with industry practice, we have a separate annual incentive plan for our marketing group, which is a profit sharing arrangement.

Stock and Long-Term Incentives

The Board believes employees should have a stake in Nexen's future and that their interests should be aligned with the interests of our shareowners. To this end, Nexen's contributions to employee savings plans are made in Nexen common shares. In addition, the Committee selects those officers and employees whose decisions and actions can most directly impact business results to participate in the TOPs and the StARs plans.

Under these plans, participating officers and employees receive grants of TOPs or StARs as a long-term incentive to increase shareowner value. The StARs Plan was introduced in 2001, and the TOP Plan (which is described below) was introduced in 2004. For employees below mid-level department managers, StARs are typically granted instead of TOPs. The grants have a five-year term and vest one-third each year of the first three years on the anniversary date of the grant. This plan is distinct from the annual incentive plan and is intended to increase the pay-at-risk component. TOPs do not provide employees the right to vote the shares that are subject to the TOPs.

To determine the number of TOPs and StARs available for distribution, we consider market information on options and other forms of long-term incentives and the dilutive impact of the programs on shareowners. The focus in 2005 was on providing differentiated awards based on performance, potential and retention risk. The total TOPs and StARs granted and shares reserved for issue under all of our stock-based compensation programs will not exceed 10% of our total outstanding shares.

TOPs and StARs Granted in the Last Three Years

Year	Issued to Non-Executive Directors	Issued to Executive Officers	Issued to Employees	Percentage of Employees Granted TOPs/StARs	Total Number of TOPs/StARs Granted
TOPS					
2005	–	592,000	2,799,500	20%	3,391,500
2004 [1]	–	1,022,000	3,202,400	11%	4,224,400
2003 [1]	–	840,000	2,913,000	11%	3,753,000
StARs					
2005	–	–	1,443,050	39%	1,443,050
2004 [1]	–	–	2,608,900	34%	2,608,900
2003 [1]	–	–	2,033,218	28%	2,033,218

Note:

1 Reflects the two-for-one split of issued and outstanding common shares that occurred on May 10, 2005 (TSX) and on May 18, 2005 (NYSE).

Executive Officer Share Ownership Guidelines

Executive officers are required to demonstrate their commitment to Nexen through share ownership, and the Board has approved the officer shareholding guidelines set out below. The period to accumulate shares is five years, and shareholdings include the net value of exercisable options, flow-through shares, shares purchased and held within the Nexen Employee Savings Plan and any other personal holdings. All executives hold the required number of shares directly or through the net value of their exercisable options. The guidelines are reviewed from time to time.

Position	Required Shareholdings
President and CEO	Three times annual salary
CFO	Two times annual salary
Other Executive Officers	One times annual salary

President and Chief Executive Officer Compensation

Competitive compensation information for our President and CEO is determined based on assessments conducted by independent compensation consulting firms that compare similar positions in oil and gas companies. Target total cash compensation (base salary plus incentive bonus) is competitive within the range of the oil and gas comparator group. CEO compensation is approved by the independent directors of the Board.

Based on the Board assessment of Mr. Fischer's achievement of objectives in 2004, his base salary was increased to $1,000,000 in April 2005. He was awarded a bonus of $900,000 under the annual incentive plan, which was 133% of his target bonus.

2004 Results	Comments	Results
Financial Performance Measures (50%)		
Net Income (25%)	Net Income was $793 million	Exceeded Target
Cash Flow (25%)	Cash Flow was $1,942 million	Exceeded Target
Other Key Qualitative and Quantitative Targets for Growth and Operation Performance (50%)		
Annual Stock Performance	5% annual rate of return including dividends	Below Target
Reserves Growth	Reserve life index of 9.2 years	Met Target
Production Volumes	250 million barrels of oil equivalent per day	Slightly Below Target
Operating Costs	Operating costs per unit of $6.15	Below Target
Environment	Zero major environmental incidents	Met Target

Mr. Fischer's responsibility is to provide direction and leadership in setting and achieving goals, which will create value for Nexen's shareowners in the short term and the long term. More specifically, his goals in 2005 were to:

- develop and implement the corporate strategy, balancing short-term growth while positioning Nexen for continued future growth;
- achieve the targets for cash flow, production, net asset value, earnings per share, cash flow per share and reserve replacement as set out in the annual operating plan;
- maintain financial flexibility and liquidity to support business strategies without undue financial risk for shareowners;
- achieve operating, finding and development and general and administrative cost performance targets set out in the annual operating plan;
- achieve top-quartile performance in safety, environmental performance and social responsibility; and
- provide for corporate management succession and development.

Mr. Fischer was also granted options to purchase 200,000 shares at an exercise price of $54.57 under the TOP Plan. Awards under the TOP Plan are a direct link to share performance and form part of the competitive overall compensation package.

In 2006, the Committee reviewed an analysis of total CEO pay and shareowner value created from the date Mr. Fischer became CEO.

CEO Total Compensation—Three-Year Look-Back

Cdn$	Total 2003–2005	2005	2004	2003
Base Salary	2,547,917	975,000	847,917	725,000
Annual Incentive	3,110,000	1,200,000	1,310,000	600,000
Sub-Total Annual	5,657,917	2,175,000	2,157,917	1,325,000
CEO Long-Term Compensation				
Value of TOPs Granted under Annual Awards [1]	6,399,490	3,110,490	1,983,000	1,306,000
Total Direct Compensation	12,057,407	5,285,490	4,140,917	2,631,000
Perquisites (Vehicle Allowance)	93,600	31,200	31,200	31,200
Total Consideration Paid/Owing to CEO	**12,151,007**	**5,316,690**	**4,172,117**	**2,662,200**
Annual Average	4,050,336			
Annual Pension Service Cost	2,668,000	724,000	1,341,000	603,000
Year-End Market Capitalization (billions)		14.5	6.3	5.8
Change over 2003-2005 in Year-End Market Capitalization	249%			

Note:
1 Estimated fair value of TOPs using the Generalized Black-Scholes option pricing model.

External Recognition and Verification

Nexen was named one of the 100 Top Employers in Canada by *Macleans* magazine and one of Alberta's Top 20 employers by Mediacorp Canada Inc. in 2005.

Independent Consultant

The Committee has engaged Mercer Human Resource Consulting (Mercer) to provide market data on CEO and other executive officers' compensation and a technical analysis of the market data in light of Nexen's compensation plans and practices. The decisions made by the Committee are the responsibility of the Committee and may reflect factors and considerations other than the information and recommendations provided by Mercer.

In addition to this mandate, Mercer provided limited general employee compensation consulting services to Nexen during the year. In 2005, Mercer conducted a compensation practices survey on behalf of Nexen, completed a small research project and a brief review of Nexen's savings plan in the UK.

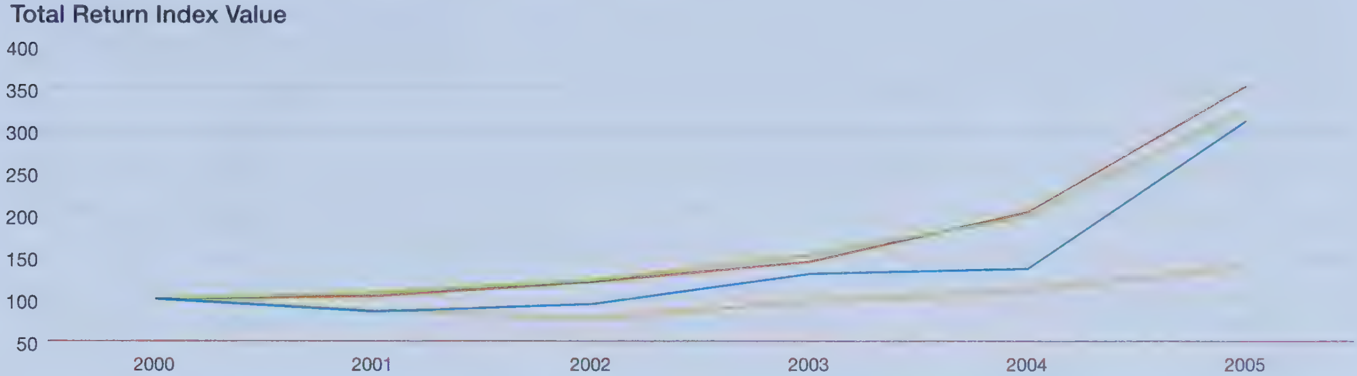
For 2005, Mercer received $33,500 for the independent assessment of executive compensation completed on behalf of the Committee and $24,400 for the other services provided to management. As well, Nexen has participated in a variety of compensation surveys both in Canada and in international locations and has purchased some of the published results.

Submitted on behalf of the Compensation and Human Resources Committee:

John Willson, Chair
Dave Hentschel
Barry Jackson
Francis Saville
Dick Thomson
Vic Zaleschuk

SHARE PERFORMANCE GRAPH

The following graph shows five years of change, ending December 31, 2005, in the value of $100 invested in our common shares, compared to the S&P/TSX Composite Index, the S&P/TSX Energy Sector Index and the S&P/TSX Oil & Gas Exploration & Production Index. Our common shares are included in each of these indices.



	2000/12	2001/12	2002/12	2003/12	2004/12	2005/12
Nexen Inc.	100.00	84.76	94.15	130.12	136.11	311.18
S&P/TSX Energy Sector Index	100.00	106.91	121.60	151.96	197.99	323.58
S&P/TSX Oil & Gas Exploration & Production Index	100.00	103.23	119.92	144.08	202.69	351.97
S&P/TSX Composite Index	100.00	87.43	76.55	97.01	111.06	137.85

Note:
Assuming an investment of $100 and the reinvestment of dividends.

Item 12. Security Ownership of Certain Beneficial Owners and Management

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS

Nexen's common shares are the only class of voting securities. Based on information known to Nexen, the following table shows each person or group who beneficially owns (pursuant to SEC Regulations) more than 5% of Nexen's voting securities at December 31, 2005.

Name and Address of Beneficial Owner	# of Shares Beneficially Owned	% of Shares
Jarislowsky Fraser Limited [1] Suite 2005, 1010 Sherbrooke Street West Montreal, Quebec, Canada, H3A 2R7	36,163,441	13.8
Ontario Teachers' Pension Plan Board [2] 5650 Yonge Street Toronto, Ontario, Canada, M2M 4H5	30,088,836	11.5
Capital Research and Management Co. [3] 333 South Hope Street, 55 Floor Los Angeles, California, USA, 90071-1406	14,206,170	5.4

Notes:
1 The beneficial owner has sole voting power over 30,636,605 shares, shared voting power over 5,526,836 shares and sole power to dispose of all shares.
2 The beneficial owner has sole voting and power to dispose of all shares.
3 The beneficial owner has sole voting power over 5,712,000 shares, sole power to dispose of all shares and disclaims beneficial ownership pursuant to Rule 13d-4.

SECURITY OWNERSHIP OF MANAGEMENT

At February 17, 2006, the following directors, certain executive officers, and all directors and executive officers as a group beneficially owned the following Nexen common shares:

Name of Beneficial Owner	Number of Shares [1]	Exercisable Stock Options [2]
Charles W. Fischer	74,440	1,146,000
Dennis G. Flanagan	12,002	13,630
David A. Hentschel	11,354	74,000
S. Barry Jackson	12,000	24,000
Kevin J. Jenkins	6,154	41,000
Eric P. Newell, O.C.	6,000	Nil
Thomas C. O'Neill	8,000	11,000
Francis M. Saville, Q.C.	20,800	39,132
Richard M. Thomson, O.C.	46,002	111,200
John M. Willson	14,002	3,666
Victor J. Zaleschuk	31,410	144,000
Laurence Murphy	48,376	99,880
Douglas B. Otten	55,873	171,460
Marvin F. Romanow	46,254	492,460
Roger D. Thomas	1,527	160,080
Thomas A. Sugalski	34	Nil
All directors and executive officers as a group (22 persons)	491,815	2,975,268

Notes:

1 The number of shares held and options exercisable by each beneficial owner represents less than 1% of the shares outstanding.

2 Includes all options exercisable within 60 days of February 17, 2006. All options held by non-executive directors are vested.

Under the terms of our TOP Plan, the Board of Directors may grant options to officers and employees and, when previously allowed for, to directors. Nexen does not receive any consideration when options are granted.

Plan Category	Number of Securities to be Issued on Exercise of Outstanding Options	Weighted-Average Exercise Price of Outstanding Options	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans
Equity compensation plans approved by shareowners	15,314,575	$28/option	17,290,038
Equity compensation plans not approved by shareowners	nil	nil	nil
Total	**15,314,575**	**$28/option**	**17,290,038**

Item 13. Certain Relationships and Related Transactions

Mr. Saville, a director, was a senior partner of Fraser Milner Casgrain LLP (FMC), Barristers and Solicitors, Calgary, Alberta, until the end of January 2004. Since then, he has been counsel with the firm. FMC has rendered legal services to Nexen during each of the last five years. Mr. Saville neither solicits nor participates in the services rendered to Nexen and does not receive any portion or percentage of the fees paid by Nexen to FMC. In addition, he is an independent director pursuant to our Categorical Standards.

Pursuant to a short-form prospectus dated October 4, 2005, Ontario Teachers' Pension Plan Board (Teachers) sold 7,500,000 shares of Nexen for gross proceeds of $406,785,000 by way of a secondary public offering. Teachers paid or reimbursed Nexen for legal, audit and filing fees in an aggregate amount of $635,000.

Item 14. **Principal Accountant Fees and Services**

In connection with its responsibilities, the Audit and Conduct Review Committee:

- met with management and the independent auditor to review and discuss the December 31, 2005 Consolidated Financial Statements;
- discussed with the independent auditor the matters required by Canadian regulators according to with Section 5751 of the General Assurance and Auditing Standards of the Canadian Institute of Chartered Accountants *Communications with Those Having Oversight Responsibility for the Financial Reporting Process* and by US regulators according to the Statement on Auditing Standards No. 61 *Communication with Audit Committees* issued by the American Institute of Certified Public Accountants;
- received written disclosures from the independent auditor required by the SEC according to the Independence Standards Board Standard No. 1 *Independence Discussions with Audit Committees*;
- discussed with the independent auditor that firm's independence; and
- oversaw the progress of the Section 404 Sarbanes-Oxley project for management and the independent auditor to report on the effectiveness of internal control over financial reporting as at December 31, 2005.

AUDIT FEES

Type of Fee	Billed in 2004	Billed in 2005	Percentage of Total Fees Billed in 2005
Audit Fees			
For the Audit of Nexen's Consolidated Financial Statements Included in our Annual Report on Form 10-K	$1,041,000	$806,500 [1]	
For the First, Second and Third Quarter Reviews of Nexen's Consolidated Financial Statements Included in Form 10-Qs	$45,000	$69,000	
For Comfort Letters and Submissions to Commissions	$9,500	$149,000	
For the Audit of Internal Control Over Financial Reporting	$630,000	$1,269,000 [2]	
Total Audit Fees	**$1,725,500**	**$2,293,500**	**66%**
Audit-Related Fees			
For the Annual Audits and Quarterly Reviews of our Subsidiary Financial Statements and Employee Benefit Plans	$296,000	$466,500	
For Audit-Related Work in Connection with Acquisitions and Divestitures	Nil	$391,000	
Total Audit-Related Fees	**$296,000**	**$857,500**	**25%**
Tax Fees			
For Tax Return Preparation Assistance and Tax-Related Consultation	$60,000	$234,000	
Total Tax Fees	**$60,000**	**$234,000**	**7%**
All Other Fees	**Nil**	**$66,000 [3]**	**2%**
Total Annual Fees	**$2,081,500**	**$3,451,000**	**100%**

Notes:

1 Consisting of $336,500 to complete the 2004 audit and $470,000 to commence the 2005 audit.

2 Consisting of $549,000 to complete the 2004 audit and $720,000 to commence the 2005 audit.

3 Annual renewal fees for an upstream information database used in our UK office.

AUDIT & CONDUCT REVIEW COMMITTEE APPROVAL

Before Deloitte & Touche LLP is engaged by Nexen or our subsidiaries to render audit or non-audit services, the engagement is approved by Nexen's Audit and Conduct Review Committee. All audit-related, tax and other services provided by Deloitte & Touche LLP since May 6, 2003, have been approved by the Audit and Conduct Review Committee.

Submitted on behalf of the Audit and Conduct Review Committee:

Tom O'Neill, Chair
Dennis Flanagan
Dave Hentschel
Barry Jackson
Kevin Jenkins
Dick Thomson

PART IV

Item 15. **Exhibits and Financial Statement Schedules**

FINANCIAL STATEMENTS AND SCHEDULES

We refer you to the index to Financial Statements and Supplementary Data in Item 8 of this report where these documents are listed.

Schedules and separate financial statements of subsidiaries are omitted because they are not required or applicable, or the required information is shown in the Consolidated Financial Statements or notes.

EXHIBITS

Exhibits filed as part of this report are listed below. Certain exhibits have been previously filed with the Commission and are incorporated in this Form 10-K by reference. Instruments defining the rights of holders of debt securities that do not exceed 10% of Nexen's consolidated assets have not been included. A copy of such instruments will be furnished to the Commission upon request.

2.2 Agreement for the Sale and Purchase of EnCana (U.K.) Limited, between EnCana (U.K.) Holdings Limited and Nexen Energy Holdings International Limited dated October 28, 2004 (filed as Exhibit 2.1 to Form 8-K dated October 29, 2004).

3.5 Restated Certificate of Incorporation of the Registrant dated June 5, 1995, and Restated Articles of Incorporation (filed as Exhibit 3.5 to Form 10-K for the year ended December 31, 1995).

3.6 Certificate of Amendment of the Articles of the Registrant dated May 9, 1996 (filed as Exhibit 3.6 to Form 10-K for the year ended December 31, 1996).

3.7 Certificate of Amendment and Articles of Amendment of the Registrant dated November 2, 2000, with respect to the name change to Nexen Inc. (filed as Exhibit 3.7 to Form 10-K for the year ended December 31, 2000).

3.9 By-Law No. 2 of the Registrant enacted December 9, 2003, being a by-law relating generally to the transaction of the business and affairs of the Registrant (filed as Exhibit 3.9 to Form 10-K for the year ended December 31, 2003).

3.10 Certificate of Amalgamation dated January 1, 2005 relating to the amalgamation of Nexen Canada Ltd., a wholly-owned subsidiary of the Registrant, into the Registrant (filed as Exhibit 1 to Form 8-K dated February 4, 2005).

3.11 Amended Articles of Amalgamation dated January 13, 2005 relating to the amalgamation of Nexen Canada Ltd., a wholly-owned subsidiary of the Registrant, into the Registrant (filed as Exhibit 2 to Form 8-K dated February 4, 2005).

3.12 Certificate of Amendment dated April 28, 2005 to effect a division of the issued and outstanding common shares of the Registrant on the basis of a two-for-one common share held (filed as Exhibit 3(i)(a) to Form 8-K dated May 2, 2005).

3.13 Articles of Amendment dated April 28, 2005 to effect a division of the issued and outstanding common shares of the Registrant on the basis of a two-for-one common share held (filed as Exhibit 3(i)(b) to Form 8-K dated May 2, 2005).

3.14 Restated Certificate and Articles of Incorporation of the Registrant dated May 20, 2005 (filed as Exhibit 3.12 to Form 10-Q for the quarterly period ended June 30, 2005).

4.29 Acquisition Agreement between the Registrant, Occidental Petroleum Corporation and Ontario Teachers' Pension Plan Board, dated March 1, 2000 (filed as Exhibit 4.29 to Form 10-K for the year ended December 31, 1999).

4.32 Amended and Restated Loan Agreement of December 29, 1988, between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders, dated November 17, 2000, amending the amount of the facility to $400 million and providing for various conforming covenant amendments to the Loan Agreement dated April 14, 1997 (as restated) (filed as Exhibit 4.32 to Form 10-K for the year ended December 31, 2000).

4.33 Restated Loan Agreement of April 14, 1997, between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders dated October 16, 2000, reducing the amount of the facility to $975 million and splitting the loan into 364-day (40%) and six-year term (60%) portions, and other various amendments (filed as Exhibit 4.33 to Form 10-K for the year ended December 31, 2000).

4.36 First Amending Agreement to the October 16, 2000 Restated Loan Agreement of April 14, 1997, between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders, dated July 31, 2001 (filed as Exhibit 4.36 to Form 10-K for the year ended December 31, 2001).

4.37 First Amending Agreement to the November 17, 2000 Amended and Restated Loan Agreement of December 29, 1988, between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders, dated August 1, 2001 (filed as Exhibit 4.37 to Form 10-K for the year ended December 31, 2001).

4.38 Second Amending Agreement to the October 16, 2000 Restated Loan Agreement of April 14, 1997, between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders, dated July 30, 2002 (filed as Exhibit 4.38 to Form 10-K for the year ended December 31, 2002).

4.39 Second Amending Agreement to the November 17, 2000 Amended and Restated Loan Agreement of December 29, 1988, between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders, dated July 31, 2002 (filed as Exhibit 4.39 to Form 10-K for the year ended December 31, 2002).

4.40 Amended and Restated Shareholder Rights Plan Agreement dated May 2, 2002 between the Registrant and CIBC Mellon Trust Company, as Rights Agent, which includes the Form of Rights Certificate as Exhibit A (filed as Exhibit 3 to Form 8-A/A dated August 20, 2002).

4.42 Trust Indenture dated April 28, 1998 between the Registrant and CIBC Mellon Trust Company providing for the issue of debt securities from time to time (filed as Exhibit 4.42 to Form 10-K for the year ended December 31, 2003).

4.43 First Supplemental Indenture dated April 28, 1998 to the Trust Indenture dated April 28, 1998 between the Registrant and CIBC Mellon Trust Company pertaining to the issuance of US$200 million, 7.40% notes due 2028 (filed as Exhibit 4.43 to Form 10-K for the year ended December 31, 2003).

4.44 Third Amending Agreement dated July 29, 2003 to the October 16, 2000 Restated Loan Agreement of April 14, 1997 between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders (filed as Exhibit 4.44 to Form 10-K for the year ended December 31, 2003).

4.45 Third Amending Agreement dated July 29, 2003 to the November 17, 2000 Amended and Restated Loan Agreement of December 29, 1988, between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders (filed as Exhibit 4.45 to Form 10-K for the year ended December 31, 2003).

4.46 Third Supplemental Indenture dated March 11, 2002 to the Trust Indenture dated April 28, 1998 between the Registrant and CIBC Mellon Trust Company pertaining to the issuance of $500 million, 7.85% notes due 2032 (filed as Exhibit 4.46 to Form 10-K for the year ended December 31, 2003).

4.47 Subordinated Debt Indenture dated November 4, 2003 between the Registrant and Deutsche Bank Trust Company Americas, pertaining to the issue of subordinated notes from time to time (filed as Exhibit 4.47 to Form 10-K for the year ended December 31, 2003).

4.48 Officer's Certificate dated November 4, 2003 pursuant to the Subordinated Debt Indenture dated November 4, 2003 between the Registrant and Deutsche Bank Trust Company Americas, pertaining to the issuance of US$460 million, 7.35% subordinated notes due 2043 (filed as Exhibit 4.48 to Form 10-K for the year ended December 31, 2003).

4.49 Fourth Amending Agreement dated November 4, 2003 to the October 16, 2003 Restated Loan Agreement of April 14, 1997, between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders (filed as Exhibit 4.49 to Form 10-K for the year ended December 31, 2003).

4.50 Fourth Amending Agreement dated November 4, 2003 to the November 17, 2000 Amended and Restated Loan Agreement of December 29, 1988, between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders (filed as Exhibit 4.50 to Form 10-K for the year ended December 31, 2003).

4.51 Fourth Supplemental Indenture dated November 20, 2003 to the Trust Indenture dated April 28, 1998, between the Registrant and CIBC Mellon Trust Company pertaining to the issuance of US$500 million, 5.05% notes due 2013 (filed as Exhibit 4.51 to Form 10-K for the year ended December 31, 2003).

4.52 Loan Agreement of November 26, 2004, between the Registrant, the Toronto Dominion Bank, as Agent, and the Lenders (filed as Exhibit 4.1 to Form 8-K dated December 7, 2004).

4.53 Fifth Supplemental Indenture dated March 10, 2005 to the Trust Indenture dated April 28, 1998, between the Registrant and CIBC Mellon Trust Company pertaining to the issuance of US$250 million, 5.20% notes due 2015 and the issuance of US$790 million, 5.875% notes due 2035 (filed as Exhibit 10.1 to Form 8-K dated March 11, 2005).

4.54* Amended and Restated Shareholder Rights Plan Agreement dated April 27, 2005 between the Registrant and CIBC Mellon Trust Company, as Rights Agent, which includes the Form of Rights Certificate as Exhibit A.

10.40 Amended and Restated Change of Control Agreements with Executive Officers dated during December, 2001 (filed as Exhibit 10.41 to Form 10-K for the year ended December 31, 2001).

10.41 Indemnification Agreements made between the Registrant and its directors and officers during 2002 (filed as Exhibit 10.41 to Form 10-K for the year ended December 31, 2002).

10.42 Indemnification Agreement made between the Registrant and one of its directors, Eric P. Newell, as of January 5, 2004 (filed as Exhibit 10.42 to Form 10-K for the year ended December 31, 2003).

10.43 Credit Agreement dated as of July 22, 2005 between the Registrant and the Toronto Dominion Bank, as Agent, and the Lenders (filed as Exhibit 10.1 to Form 8-K dated July 28, 2005).

10.44 Guarantee dated as of July 22, 2005 as Schedule K to the Credit Agreement (filed as Exhibit 10.2 to Form 8-K dated July 28, 2005).

10.45 Termination of Employment and Special Separation Agreement between the Registrant and Mr. Sugalski dated January 28, 2005 (filed as Exhibit 10.1 to Form 8-K/A dated August 18, 2005).

11.1* Statement regarding the Computation of Per Share Earnings for the three years ended December 31, 2005.

16.1 Letter re change in certifying accountant (filed as Exhibit 16.1 to Form 8-K filed July 17, 2002).

21.1* Subsidiaries of the Registrant.

23.1* Consent of Independent Registered Chartered Accountants.

31.1* Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2* Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1* Certification of periodic report by Chief Executive Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2* Certification of periodic report by Chief Financial Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

99.1* Opinion of Internal Qualified Reserves Evaluator on National Instrument 51-101 Form F2 as required by certain Canadian securities regulatory authorities.

* Filed with this 10-K.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Company has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on February 23, 2006.

NEXEN INC.

By: /s/ Charles W. Fischer
Charles W. Fischer
President, Chief Executive Officer
and Director (Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 23, 2006.

/s/ Dennis G. Flanagan
Dennis G. Flanagan, Director

/s/ David A. Hentschel
David A. Hentschel, Director

/s/ S. Barry Jackson
S. Barry Jackson, Director

/s/ Kevin J. Jenkins
Kevin J. Jenkins, Director

/s/ Eric P. Newell
Eric P. Newell, Director

/s/ Thomas C. O'Neill
Thomas C. O'Neill, Director

/s/ Francis M. Saville
Francis M. Saville, Director

/s/ Richard M. Thomson
Richard M. Thomson, Director

/s/ John M. Willson
John M. Willson, Director

/s/ Victor J. Zaleschuk
Victor J. Zaleschuk, Director

/s/ Charles W. Fischer
Charles W. Fischer
President, Chief Executive Officer
and Director (Principal Executive Officer)

/s/ Marvin F. Romanow
Marvin F. Romanow
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ Michael J. Harris
Michael J. Harris
Controller
(Principal Accounting Officer)

/s/ John B. McWilliams
John B. McWilliams
Senior Vice President, General Counsel
and Secretary

/s/ Kevin J. Reinhart
Kevin J. Reinhart
Vice President, Corporate Planning
and Business Development

EXHIBIT 31.1

Certifications

I, Charles W. Fischer, certify that:

1. I have reviewed this annual report on Form 10-K of Nexen Inc.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and;

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2006

/s/ Charles W. Fischer
Charles W. Fischer
President, and Chief Executive Officer

EXHIBIT 31.2

Certifications

I, Marvin F. Romanow, certify that:

1. I have reviewed this annual report on Form 10-K of Nexen Inc.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rule 13a-15(f) and 15d-15(f)) for the registrant and we have:

   (a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and;

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 23, 2006

/s/ Marvin F. Romanow
Marvin F. Romanow
Executive Vice President,
and Chief Financial Officer

EXHIBIT 32.1

Certification of Periodic Report

I, Charles W. Fischer, President and Chief Executive Officer of Nexen Inc., a Canadian Corporation (the "Company"), certify, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Annual Report on Form 10-K of the Company for the year ended December 31, 2005 as filed with the Securities and Exchange Commission on the date hereof (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 23, 2006

/s/ Charles W. Fischer
Charles W. Fischer
President, and Chief Executive Officer

A signed original of this written statement required by Section 906 has been provided to Nexen Inc. and shall be retained by Nexen Inc. and furnished to the Securities and Exchange Commission or its staff on request.

EXHIBIT 32.2

Certification of Periodic Report

I, Marvin F. Romanow, Executive Vice President and Chief Financial Officer of Nexen Inc., a Canadian Corporation (the "Company"), certify, pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) the Annual Report on Form 10-K of the Company for the year ended December 31, 2005 as filed with the Securities and Exchange Commission on the date hereof (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: February 23, 2006

/s/ Marvin F. Romanow
Marvin F. Romanow
Executive Vice President,
and Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to Nexen Inc. and shall be retained by Nexen Inc. and furnished to the Securities and Exchange Commission or its staff on request.

In complying with the evolving complexity of regulatory requirements for reporting our high-quality reserves and performance data, we make **on**going efforts to communicate clearly and effectively.

see the **value**

corporate and other information

investments production growth see the **value**

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nexen